INTERMOUNTAIN GENERATING STATION

INTERMOUNTAIN POWER PROJECT
INTERMOUNTAIN GENERATING STATION

CONDENSER RETUBING STUDY

BLACK & VEATCH PROJECT 09255
FILE NO. 09255.42.2604

IPP
INTERMOUNTAIN POWER PROJECT

BLACK & VEATCH/consulting engineers

CONTENTS

		Page
1.0	INTRODUCTION	1-1
2.0	SUMMARY	2-1
	2.1 SUMMARY OF IMPORTANT INFORMATION	2-1
	2.2 CONCLUSIONS AND RECOMMENDATIONS	2-2
3.0	BACKGROUND INFORMATION	3-1
	3.1 HISTORY AND ANALYSIS OF EXISTING CONDENSER TUBES	3-1
	3.2 TELEPHONE SURVEY OF UTILITIES	3-7
4.0	EFFECTS OF ALTERNATE TUBE MATERIALS ON CONDENSER DESIGN	4-1
	4.1 ALTERNATE TUBE MATERIALS	4-1
	4.2 SYSTEM PERFORMANCE	4-3
	4.3 CONDENSER DESIGN COMPATIBILITY	4-4
5.0	EVALUATION OF ALTERNATE TUBE MATERIAL	5-1
	5.1 COST ANALYSIS	5-1
	5.2 OTHER CONSIDERATIONS	5-1
6.0	CHEMICAL TREATMENT CONSIDERATIONS	6-1
	6.1 OBJECTIVE	6-1
	6.2 CIRCULATING WATER CHEMICAL FEED DESIGN	6-1
	APPENDIX A DOCUMENT LIST	
	APPENDIX B TELEPHONE MEMORANDUMS	

LIST OF TABLES

TABLE 3-1	TELEPHONE SURVEY RESULTS	3-8
TABLE 4-1	EFFECTS OF TUBE WALL GAUGE ON CIRCULATING WATER SYSTEM	4-5
TABLE 4-2	CONDENSER PERFORMANCE AT DESIGN CONDITIONS	4-6
TABLE 4-3	REDUCTION IN PEAK TURBINE OUTPUT	4-7
TABLE 4-4	REPLACEMENT TUBESHEET CAPITAL COSTS	4-9
TABLE 4-5	UPLIFT ANALYSIS RESULTS	4-13

CONTENTS (Continued)

LIST OF TABLES (Continued)

		Page
TABLE 4-6	ALLOWABLE TUBE SUPPORT SPACING	4-14
TABLE 5-1	COMPARATIVE COST EVALUATION	5-2
TABLE 5-2	EQUIVALENT CAPITAL INVESTMENT OF OPERATING COSTS--BOTH UNITS	5-3
TABLE 6-1	COMPARISON OF THE DESIGN WATER ANALYSES OF THE CIRCULATING WATER MAKEUP TREATMENT SYSTEM WITH DMAD RESERVOIR WATER SAMPLE TAKEN JANUARY 4, 1988	6-4
TABLE 6-2	WATER DATA FOR CHICKEN CREEK AS PROVIDED BY IPSC	6-5

1.0 INTRODUCTION

The purpose of this study is to evaluate alternate tube materials and recommend the most appropriate material for retubing Units 1 and 2 condensers. The following tube materials are considered.

- 90-10 Cu Ni--(20 BWG).
- 70-30 Cu Ni--(20 BWG).
- Alloy 29-4C--(22 BWG).
- AL-6XN--(22 BWG).
- Sea-Cure--(22 BWG).
- Titanium--(22 BWG).

These tube materials are evaluated to determine their suitability based on the currently known failures and the impact on other condenser components (water boxes, tubesheets, support plates), tube velocity, and cathodic protection. An evaluated cost for replacement condenser tubes is developed from the bids received for each material alternative. The bid analysis is summarized separately.

Each tube material is evaluated to determine its compatibility with the existing condenser, effect on condenser performance, heat rate, and complete cycle heat rejection system. Chemical feed to minimize corrosion attack is also considered.

2.0 SUMMARY

The following statements briefly summarize the information presented in this study. A conclusion based on this information provides a recommended condenser tube material best suited for use at the Intermountain Generating Station.

2.1 SUMMARY OF IMPORTANT INFORMATION

- The performance of copper-nickel condenser tubes has been unsatisfactory at the Intermountain Generating Station. Therefore, copper-nickel is unacceptable as a replacement condenser tube material.
- Based on accelerated corrosion testing by Intermountain Power Service Corporation, titanium and the stainless steels are resistant to pitting in the Intermountain Generating Station circulating water environment.
- Titanium and the stainless steel tube materials under consideration are compatible with the existing condenser design with the appropriate modifications such as impressed current cathodic protection, tubesheet coatings, and anchor bolting to compensate for uplift.
- The use of the existing tubesheets is recommended due to fabrication and delivery problems, along with possible construction schedule delays associated with replacement tubesheets.
- The application of a 100 percent solids epoxy resin coating to the aluminum bronze tubesheets and installation of an impressed current cathodic protection system are strongly recommended with installation of titanium or stainless steel condenser tubes.
- The differences in the performance characteristics of the titanium and stainless steels do not constitute a determining factor in tube selection relative to other aspects being considered.
- Due to the corrosive and highly variable water quality, the best available material should be used.

- Titanium is the most noble condenser tube material of the alloys considered.
- Titanium has the lowest evaluated cost of the alternate materials considered technically acceptable.

2.2 CONCLUSIONS AND RECOMMENDATIONS

Titanium, the most noble tube material, is recommended for use with the existing tubesheets. The tubesheets and water boxes should be protected with coatings and an impressed current cathodic protection system.

3.0 BACKGROUND INFORMATION

3.1 HISTORY AND ANALYSIS OF EXISTING CONDENSER TUBES

The Intermountain Generating Station consists of two units, each 750 MW. The design circulating water flow to each unit's condensers is 288,000 gpm. This corresponds to a design velocity of 6.0 fps in the condenser tubes.

The makeup to the circulating water is lime softened Sevier River (DMAD Reservoir) water. The circulating water system includes two cooling towers to reject the waste heat. The constituents in the circulating water are concentrated, due to evaporation from the cooling towers. The cycles of concentration are controlled by adjusting blowdown rate from the cooling towers and making up to the circulating water system as needed with softened water.

Each unit has a triple pressure main condenser consisting of three separate shells. The two end shells are vertically divided with two water boxes on each end and are arranged for a single pass through each side. The middle shell is horizontally and vertically divided with four water boxes on each end and is arranged for two water passes. Each condenser contains 45,250 tubes and each condenser shell contains 150,000 square feet of tube surface area. The tubes have a 1-inch outside diameter and are 38 feet 4-1/4 inches in total length, 38 feet effective length. The tubes are 20 BWG, 90-10 copper-nickel ASTM B543 for the main condensing zones and 20 BWG, 70-30 copper-nickel ASTM B543 for the air removal and exhaust impingement zones. The tubesheets in the high-pressure condenser shell and the low-pressure condenser shell are 2-1/16 inch thick, and in the intermediate-pressure condenser shell, the tubesheets are 1-1/2 inch thick. All tubesheets are fabricated of aluminum bronze, ASTM B171. The tubesheets are cathodically protected with sacrificial zinc anodes. The condenser tubes are supported by twelve 3/4-inch thick carbon steel support plates in each divided shell. The support plates are spaced on 35-inch centers. The water boxes are coated carbon steel.

The tubes for Unit 1 were delivered to the site between October 20, 1983 and December 1, 1983 and were installed between June 12, 1984 and September 20, 1984. The tubes for Unit 2 were delivered to the site between June 21, 1984 and September 20, 1984 and were installed between April 12, 1985 and July 8, 1985. Initial operation (turbine roll) on Unit 1 began in February 1986 with commercial operation in June 1986. The initial and commercial operation dates for Unit 2 were February 1987 and May 1987, respectively.

When the condenser tubes were received onsite and inspected, IPSC expressed concern regarding "black" spots on the exterior surface of the tubes. Metallographic and chemical analyses were performed on the tubes. The results of these evaluations are summarized as follows.

- A report by C. H. Pitt, of the University of Utah, dated April 22, 1985, concluded that the tubes would fail in service due to rapid perforation.
- H. K. Kalavick, in a Calgon report dated May 7, 1985, performed a metallographic evaluation of the new condenser tubes. In this evaluation, the internal surfaces were found to be smooth and bright with no surface irregularities. The report predicted, however, that the tubes would give poor service due to failures from stress corrosion cracks or chemical attack on the exterior surfaces.
- Report C-3615 by John Wakamatsu, Los Angeles Department of Water and Power Laboratory and Technical Services, dated July 29, 1985, presented results of a chemical analysis of corrosion deposits from a new 90-10 condenser tube. The corrosion deposits had resulted from an experiment performed by J. Kalis from November 19-24, 1984. The 1-inch long tube section from the experiment was examined and was found to be lightly corroded and pitted.
- A report by L. Caruso, Phelps Dodge Corporation, dated August 23, 1985, discussed the susceptibility of copper alloys

to corrosion if proper lay-up procedures were not followed. The report took exception to the earlier findings of C. H. Pitt and H. K. Kalavick, who predicted early failures.

- Report C-3761 by M. McGee, Los Angeles Department of Water and Power Laboratory and Technical Services, dated September 4, 1985, also found by chemical analysis that the tubes met the alloy requirements. The report indicated that the external surface appearance of the tubes was cause for rejection.

J. Kalis of IPSC reported on February 25, 1987 that structural damage and leaking pitted tubes were found in Unit 1. The inspection of the condenser was made following a black trip incident on February 13, 1987. A report by E. Conley of Heat Exchanger Systems, Inc. dated March 27, 1987 attributed the tube failures to microbiologically induced corrosion resulting in sulfide attack on the tube metal. It was later determined that the tube sample evaluated was not representative of the pitting attack which predominated.

Subsequent to commercial operation, numerous analyses and inspections were performed on corroded condenser tube samples cut from the condenser. Los Angeles Department of Water and Power Laboratory and Technical Services, in a report dated June 16, 1987, provided results of a metallurgical examination of a 1-foot long section of condenser tube from Unit 1. Several deep corrosion pits and patches of shallower pits were found on the interior surface of the tube. One of the deep pits had perforated the tube. The interior tube surface was found to be fairly bright with no buildup of the protective passivation film. The report indicated that there was no evidence of stress corrosion cracking, denickelification, microbiological attack, or impingement corrosion. The pitting was postulated as being caused by deposit corrosion. The report concluded that the circulating water quality, including its treatment and additives, is the most likely cause of the tube corrosion.

Dr. Gary Was, University of Michigan, prepared a report dated July 8, 1987 on the pitting in the condenser tubes in Unit 1. Through X-ray photoelectron spectroscopy analysis, Dr. Was found that the pit deposits were filled with cuprous chlorides. The absence of chloride in the surface films indicated that the formation of cuprous chloride is occurring only locally. The corrosion mechanism postulated is that cuprous chloride is trapped beneath the thin protective layer of cuprous oxide and is hydrolyzed to form cuprous oxide and hydrochloric acid. The resulting low pH solution in the pit promoted conditions for pit growth. No evidence of sulfur, using the X-ray photoelectron spectroscopy technique, was found, signifying that sulfide attack is not contributing to the pitting mechanism.

A second report by E. Conley of Heat Exchanger Systems concluded that thermally accelerated plug denicklification appears to be the primary corrosion mechanism. Black trips were theorized to be a cause of defective ID film formation. Iron and silt coprecipitation and continuous Amertap operation were reported to be contributing factors. The tube material and its microstructure reportedly did not contribute to the corrosion experience.

A report prepared by A. W. Blackwood and A. M. Hirt of Structure Probe, dated September 28, 1987, indicated that the reddish film on the interior of a sample condenser tube is iron-rich and that the tube surface is depleted of nickel. The corrosion mechanism was postulated to involve both sulfur and chlorine. The typical protective film which forms on copper-nickel surfaces, usually either brown or green in color, was not observed.

McCrone Associates - Atlanta, reported September 30, 1987, five optically distinct types of corrosion products found in a condenser tube sample using energy-dispersive spectrometry. It was not designated in the report whether the sample tube was taken from Unit 1 or Unit 2, but it is assumed it was from Unit 1 because a second report from McCrone Associates, referenced later, is specifically for tube samples from Unit 2. The most prevalent corrosion product, and the third most abundant type analyzed, indicated copper oxides, with a minor amount of chlorine. The second and fourth most abundant corrosion product types contained predominately iron oxides and lesser amounts of chlorine, sulfur, phosphorus, silicon, aluminum, magnesium, and calcium. The fifth type analyzed indicated only sulfur in addition to the copper and nickel. Based on optical microscopy techniques the sulfur was determined to be a monohydrate of copper sulfate. The corrosion mechanism postulated based on these tests results is anion attack on the copper-nickel alloy, with chloride attack being the most significant.

Results from Scanning Electron Analysis Laboratories, Inc. submitted October 6, 1987 by S. Sheybany, using an energy dispersive X-ray microprobe to analyze the corrosion products, showed major levels for copper and oxygen, and minor levels for iron, silica, calcium, nickel, phosphorus, sulfur, and chlorine. An X-ray diffraction technique showed the corrosion products to be primarily copper oxide and, to a lesser degree, nickel oxide and iron oxide. Mr. Sheybany did not attempt to postulate a failure mechanism.

A second report from Structure Probe, Technical Report 80358, prepared by Blackwood and Hirt, dated December 10, 1987, concluded that an active corrosion mechanism is taking place on Unit 1 condenser tubes. The adherent protective film necessary for the successful use of copper alloys has not formed on the interior tube surface. Structure Probe suggested that the corrosion problem is probably due to water chemistry, specifically due to chloride attack. A third report from Structure Probe, Technical Report 80362 dated December 29, 1987, concluded that the Unit 2 condenser tubes are corroding in a similar manner to the Unit 1 tubes, based on chloride attack.

A second and third report from McCrone Associates - Atlanta were submitted December 22, 1987 and January 12, 1988 by C. Bowers regarding the analysis of two corroded condenser tubes from Unit 1 and three corroded condenser tubes from Unit 2. Like the earlier analysis by McCrone Associates on tubes from Unit 1, the most prevalent corrosion products were found to be copper oxides, with minor amounts of chlorine. Other elements found in trace amounts in these analyses included silicon, iron, nickel, calcium, phosphorus, sulfur, and manganese. As in the earlier analysis on Unit 1 tubes, the corrosion mechanism for both Units 1 and 2 was presumed to be chloride attack.

Eddy current testing of 10 percent of the condenser tubes in both Units 1 and 2 was conducted during November and December 1987. The eddy current testing was performed by Heat Exchanger Systems Inc. with their results included in a report dated January 26, 1988. Pitting was found in both units' condensers, with Unit 2 pitting being much worse. In Unit 1, 9.6 percent of the tubes tested showed pitting greater than 20 percent of the wall thickness in depth, with 0.6 percent greater than 60 percent through the wall. In Unit 2, 52 percent of the tubes tested showed pitting greater than 20 percent of the wall thickness in depth, with 6 percent greater than 60 percent through the wall. The size of the pits in Unit 1 were found to be smaller in diameter than the pits in Unit 2. In Unit 1, 36 percent of the tubes tested had pit diameters greater than 40 mils, with 4 percent greater than 80 mils. Unit 2, however, had 96 percent of the tubes having pit diameters greater than 40 mils, with 47 percent greater than 80 mils. An IPSC letter dated January 12, 1988 by S. G. Chapman also summarizes the results of the eddy current testing.

A report by LADWP-MES issued January 25, 1988 disclosed that the Unit 1 tubes were subjected to periods of adverse water conditions, minimally aerated and very low flow, resulting in areas of stagnation. These conditions are noted to be conducive to inhibiting formation of a protective film, thus allowing localized pitting to occur.

A test report dated February 12, 1988 by E. Conley of Heat Exchanger Systems, provided results of cyclic potentiodynamic hysterersis (electrochemical) analysis and of classical immersion corrosion tests performed on the 90-10 and 70-30 copper-nickel alloys and on the other materials being considered for tube replacement. The 90-10 and 70-30 copper-nickel alloys were shown to be vulnerable to localized corrosion by the electrochemical technique and by the immersion technique due to an inability of the alloys to form a protective oxide film in the circulating water. The other tube materials tested, titanium, AL-6XN, AL 29-4C, and Sea-Cure, were not shown to be vulnerable to localized corrosion using the electrochemical technique. An insufficient period of time made it difficult to evaluate the susceptibilty of the non-copper materials to corrosion in the circulating water using the immersion technique.

The initial concerns about the tube exterior surfaces in the as-shipped condition have been proven unfounded. A normal black oxide protective film has formed on the exterior surfaces and no reports of exterior corrosion have been reported.

Performance of the present copper-nickel tube materials have been shown to be unsatisfactory due to pitting of internal surfaces. The extensive testing performed to date has identified numerous factors which may be contributing to the poor performance, including black trips, silting, stagnant conditions, Amertap operation, and anion (chloride) attack. Although the attack mechanism has not been clearly defined, it appears certain that the basic problem is an inability to establish a uniform protective oxide film in this unique circulating water environment. This condition leads to localized pitting attack. Additional testing would be necessary to determine if adjustments in the water chemistry would produce a stable surface film. Such tests take too long to be considered in the evaluation of replacement tube materials. However, testing is continuing in an attempt to determine the reason for the failure of the copper-nickel tubes to form an effective protective film and to establish additional experience with the alternative replacement tube materials.

3.2 TELEPHONE SURVEY OF UTILITIES

A telephone survey of utilities was performed to determine utility experience with 90-10 copper-nickel condenser tubes in freshwater, cooling tower applications. The utilities that have replaced 90-10 copper-nickel condenser tubes were identified through tube suppliers. Table 3-1 summarizes the pertinent information obtained. Copies of the telephone memoranda are included in Appendix B.

Of the utilities reporting early tube failure of 90-10 copper-nickel tubes, five years or less service life, all indicated severe pitting or tube wall thinning. Failure mechanisms postulated include underdeposit corrosion caused by tenacious silica deposits (Navajo Plant), localized pitting caused by sulfide attack and low flow conditions (Paradise Station), and severe pitting (Brandon Shores). Valid conclusions based on

TABLE 3-1. TELEPHONE SURVEY RESULTS

Station	Cooling Water	Original Tube Material	Original Tubesheet Material	Tube Failure	Replacement Tube Material	Replacement Tubesheet Material	Original Water Box Coated?	Water Box Coated Now?	Original Tubesheet Coated?	Tubesheet Coated Now?	Original Cathodic Protection?	Cathodic Protection Now?
SRP-Navajo	Cooling Tower Freshwater	90-10	Silicon Bronze	(1)	AL-6XN	N/A	Yes	Yes	No	No	No	Yes
TVA-Paradise	Cooling Tower Freshwater	90-10	Carbon Steel	(2)	N/A	N/A	Yes	N/A	No	N/A	No	N/A
TVA-Widow's Creek	Once-Through Freshwater	90-10	Muntz Metal	(3)	90-10	N/A	N/A	N/A	No	Being Considered	No	No
KCP&L-Iatan	Once-Through Freshwater	90-10 and 70-30	Muntz Metal	(4)	N/A	N/A	Yes	N/A	No	N/A	N/A	N/A
BG&E-Brandon Shores	Cooling Tower Brackish	90-10 and 70-30	N/A	(5)	Being Researched	N/A	Yes	N/A	No	N/A	No	N/A
TU-Comanche Peak	Once-Through Brackish	90-10	Carbon Steel	(6)	Titanium	Titanium/ Carbon Steel Clad	Yes	Yes	No	Clad	No	Being Considered

(1) Cause of failure attributed to underdeposit attack caused by tenacious silica deposits. Corrosion found primarily in hottest zones of condenser.

(2) 90-10 condenser tubes in service about four years. Eddy current testing shows pits 50 to 60 percent through the wall. Localized pitting thought to be caused by sulfide attack and low flow conditions. 85-15 Cu Ni, Sea-Cure, and AL-6XN being considered for tube replacement.

(3) 90-10 condenser tubes have provided 30-year service life.

(4) Condenser retubing being considered for 1990-1991. Severe erosion, caused by sand and silt, experienced at tube inlets. Presently, tube inlets are coated for erosion protection.

(5) Four years operation on condenser. Failure mechanism not known, but severe pitting experienced. Replacement tube material not yet determined.

(6) Tube replacement reported as not being corrosion related, but it was later learned from SPECO that corrosion did occur and was related to improper wet layup.

N/A--Not applicable or information not known.

the survey are not possible because few failures of 90-10 copper-nickel have been reported in cooling tower installations, failure mechanisms vary or are unknown, and service conditions differ.

Observations based on the above data are as follows.

- Copper alloy tubes in freshwater, cooling tower applications that have earlier than expected service failures have been replaced with tube materials other than the copper alloys.
- The existing tubesheets were reused whenever possible.
- Cathodic protection was added or is being considered where noble tube materials are installed in less noble tubesheets.
- The condenser water box is nearly always protected with a coating.

4.0 EFFECTS OF ALTERNATE TUBE MATERIALS ON CONDENSER DESIGN

4.1 ALTERNATE TUBE MATERIALS

The following condenser tube materials are considered in this study.

- 90-10 copper-nickel, ASTM B543-C70600, 20 BWG, welded or ASTM B111-C70600, 20 BWG, seamless.
- 70-30 copper-nickel, ASTM B543-C71500, 20 BWG, welded or ASTM B111-C71500, 20 BWG, seamless.
- Alloy 29-4C, ASTM A268, 22 BWG, welded.
- AL-6XN, ASTM A450 and B676, Class 4, 22 BWG, welded.
- Sea-Cure, ASTM A268, 22 BWG, welded.
- Titanium, ASTM B338, Grade 2, 22 BWG, welded.

4.1.1 <u>90-10 Copper-Nickel</u>

Ninety-ten copper-nickel tubes are presently installed at Intermountain Generating Station Units 1 and 2 except in the air removal and steam impingement zones where 70-30 copper-nickel tubes are used. The 90-10 copper-nickel tubes are not used in the air removal and steam impingement zones of the condenser since 70-30 copper-nickel tubes provide better resistance to high concentration of ammonia and to the erosive effect of steam impingement. The 90-10 copper-nickel tubes are used extensively in freshwater, brackish water, and seawater applications.

This material is compatible with the existing aluminum bronze tubesheet material.

4.1.2 <u>70-30 Copper-Nickel</u>

Seventy-thirty copper-nickel tubes offer improved resistance to stress corrosion cracking, chloride attack, and the action of ammonia and ammonia compounds. For these reasons, 70-30 copper-nickel is used in seawater and brackish water circulating water applications, particularly in the air removal zone. However, some problems have been reported with 70-30 copper-nickel in seawater applications due to sulfide attack and underdeposit pitting.

This material is compatible with the existing tubesheet material.

4.1.3 Alloy 29-4C

Alloy 29-4C is a 29 percent chromium, 4 percent molybdenum, ferritic stainless steel developed by Allegheny Ludlum specifically for brackish or seawater-cooled condensers. This material also contains 0.5 percent titanium and 0.3 percent nickel. Although this alloy is fairly new and has limited operating experience, it has been used satisfactorily in existing condensers. Several condensers are fully tubed with Alloy 29-4C and numerous others have sample tubes of Alloy 29-4C installed. The first sample tubes were installed in 1975, and the first fully tubed condenser went into operation in late 1980.

The galvanic compatibility of this alloy with aluminum bronze tubesheets is considered fair. Impressed current cathodic protection and protective coatings for the existing tubesheets and water boxes would be required. The material is susceptible to hydrogen embrittlement if the cathodic protection system is overdriven.

4.1.4 AL-6XN Alloy

AL-6XN alloy is a superaustenitic stainless steel which has been developed by Allegheny Ludlum Corporation as an extension of AL-6X. AL-6XN is a 20 percent chromium, 25 percent nickel, 6 percent molybdenum austenitic stainless steel with 0.2 percent nitrogen. The nitrogen content of the AL-6XN alloy serves to further increase pitting resistance as well as increase the strength of the alloy. The overall corrosion resistance of AL-6XN is greater than the ferritic stainless steel 29-4C, but resistance to chloride crevice corrosion is equal or slightly less.

Like 29-4C, the galvanic compatibility of AL-6XN alloy with aluminum bronze tubesheets is considered fair. An impressed current cathodic protection system and protective coatings for the existing tubesheets and water boxes would be required. This alloy is reported to be less susceptible to hydrogen damage than the other stainless steel alloys considered.

4.1.5 Sea-Cure

Sea-Cure is a 27.5 percent chromium, 3.5 percent molybdenum, 1.2 percent nickel, 0.5 percent titanium, ferritic stainless steel alloy. This alloy, manufactured by Trent Tube, A Division of Crucible Materials Corporation, was designed for increased resistance to pitting and crevice corrosion in brackish water, seawater, or polluted water-cooled condensers. This alloy is also relatively new with some operating experience. However, extensive test installations have been in service on numerous power plant condensers, some for more than seven years, and there are several fully tubed condensers in service.

Like other stainless steel alloys, the galvanic compatibility of Sea-Cure with aluminum bronze tubesheets is fair and would require an impressed current cathodic protection system and protective coatings for the existing tubesheets and water boxes. Like alloy 29-4C, it is susceptible to hydrogen embrittlement.

4.1.6 Titanium

Titanium is the most corrosion resistant of all the alloys investigated. The galvanic compatibility of titanium with the existing aluminum bronze tubesheet is fair. With the existing aluminum bronze tubesheets, an impressed current cathodic protection system would be required. This system would have to be carefully maintained. If the impressed current cathodic protection system is severely overdriven, hydriding of the titanium tube ends may occur. In addition, protective coatings for the tubesheets and water boxes would be required.

4.2 SYSTEM PERFORMANCE

The impact of the condenser materials on unit performance was evaluated for valves wide open and 5 percent overpressure, rated unit load, 75 percent of rated load, and 50 percent of rated load.

The following assumptions were made to complete the calculations.

- 36,000 gpm maintained through the auxiliary cooling equipment.
- Cooling tower performance--100 percent.

- Cooling tower recirculation allowance--2 F.
- Condenser cleanliness--85 percent.
- Unit load model, economic criteria, and wet-bulb temperatures as given in the Project Design Manual (File No. 9255.23.0200).

The condenser cleanliness of 85 percent is used for comparison. However, it is expected that with the existing tube cleaning system, titanium and stainless steel tube cleanliness can be maintained closer to 90 percent which would improve the heat transfer performance of these materials.

The circulating water flow through condenser shells A and C is 192,000 gpm with 20 BWG tubes. The circulating flow through condenser Shell B is 96,000 gpm with 20 BWG tubes. For materials with 22 BWG tubes, the increase in tube inside diameter allows more flow through the system with a decreased pumping head. The resulting flow through condenser shells A and C using 22 BWG tubes is 194,000 gpm. The resulting flow through condenser Shell B using 22 BWG tubes is 97,000 gpm. The higher flow reduces the range across the condenser and cooling tower, and the tube velocities decrease due to the larger inside diameter. The effects of tube wall thickness on the circulating water system are summarized in Table 4-1. The results of the condenser performance calculations for the various tube materials are summarized in Table 4-2. These results are based on the original condenser design heat loads.

The change in materials will impact the peak output expected from the unit while operating at valves wide open and 5 percent overpressure coincident with the 1 percent wet-bulb temperature. These performance impacts are estimated as shown in Table 4-3.

Operating costs associated with these system impacts are developed based on the unit load model, average monthly wet-bulb temperatures, and the project economic criteria. These costs are summarized in Table 5-2.

4.3 CONDENSER DESIGN COMPATIBILITY

The following sections discuss the effects of the alternate tube materials considered in this study on the mechanical design of the condenser.

TABLE 4-1. EFFECTS OF TUBE WALL GAUGE ON CIRCULATING WATER SYSTEM

	Tube Wall	
	20 BWG	22 BWG
Circulating Water Pumps		
Flow, gpm	324,000	327,000
Head, feet	59.0	58.6
Efficiency, percent	92.5	92.5
Power, kW	4,054	4,064
Tube Velocity		
Shells A, B, and C	6.0	5.9

TABLE 4-2. CONDENSER PERFORMANCE AT DESIGN CONDITIONS

	90-10 Cu Ni 20 BWG	70-30 Cu Ni 20 BWG	Alloy 29-4C 22 BWG	AL-6XN 22 BWG	Sea-Cure 22 BWG	Titanium 22 BWG
Circulating Water Temperature Rise, F	25.8	25.8	25.5	25.5	25.5	25.5
Condenser Back Pressure, inches Hg abs						
LP shell	2.34	2.42	2.51	2.55	2.45	2.51
IP shell	2.80	2.87	2.94	2.97	2.89	2.94
HP shell	3.36	3.46	3.56	3.61	3.49	3.56
Average	2.83	2.92	3.00	3.04	2.94	3.00
HEI Material Correction Factor	0.94	0.87	0.81*	0.79*	0.85*	0.81
Net Turbine Heat Rate, Btu/kWh	7,820	7,830	7,841	7,847	7,833	7,841

*Based on recommended factor provided by tube manufacturer. No HEI correction factors presently exist for these materials.

TABLE 4-3. REDUCTION IN PEAK TURBINE OUTPUT*

Tube Material	Reduced Output kW
90-10 Cu Ni	Base
70-30 Cu Ni	1,067
Alloy 29-4C	2,263
AL-6XN	2,754
Sea-Cure	1,415
Titanium	2,263

*Reduction in output based on operation at valves wide open, overpressure, and the 1 percent wet-bulb temperature.

4.3.1 Tubesheet Compatibility

The two major aspects to consider when evaluating the tubesheet compatibility are the galvanic difference between the tube and tubesheet and the integrity of the tube to tubesheet joint.

The best tubesheet to use for galvanic compatibility is a tubesheet made of the same material as the tubes. The existing aluminum bronze has proven to be acceptable with 90-10 copper-nickel and 70-30 copper-nickel tubes. The ideal tubesheet for titanium tubes is titanium. The ideal tubesheet for AL-6XN tubes is AL-6XN. Sea-Cure and 29-4C are ferritic stainless steels and are not available as sheet stock. Therefore, an available material as near as possible galvanically to these alloys, yet less noble, would be the preferred tubesheet. If the tube and tubesheet materials are not identical, the tubes must be more noble than the tubesheets to assure that any galvanic corrosion would take place on the thick tubesheets rather than the thinner tubes. The preferred tubesheet material for use with Sea-Cure and 29-4C tubes is 316L stainless steel.

Budgetary pricing and delivery schedules for replacement tubesheets have been received from several vendors. Conceptual capital costs and delivery schedules are shown in Table 4-4.

The pricing for the AL-6XN tubesheets includes the cost of splicing since the sheet stock is not available large enough to fabricate tubesheets as one piece. This would require butt welding two sheets together and drilling of tube holes in the weld area. This is not recommended. The pricing for titanium includes the cost of shell flange and neck assemblies for a bolted tubesheet since titanium cannot be welded to the shell, which is the present condenser design. Therefore, the titanium tubesheet installation would require more time than AL-6XN or 316L stainless steel tubesheets which can be welded to the shell.

If the existing tubesheets are to be used with stainless steel or titanium tubes, a protective tubesheet coating would be required in conjunction with an impressed current cathodic protection system.

The protective coating for the existing tubesheets should be a 100 percent solids epoxy resin. Budgetary pricing has been received for

TABLE 4-4. REPLACEMENT TUBESHEET CAPITAL COSTS

Tubesheet Material	Cost $	Delivery weeks after order
316L Stainless Steel	360,000	14 - 16
AL-6XN	790,000	20 - 24
Titanium	940,000	24 - 28

providing the coating, surface preparation, and application of a coating of this type. The conceptual capital cost is $200,000 for each unit. The tubesheet coating should be inspected yearly and repaired as required. It is estimated that the cost of maintaining the coating would be $20,000 per year (1988 dollars).

The function of a cathodic protection system is to protect, to the extent practical, all wetted metals in the system from corrosion. The system consists of the tubes, the tubesheet, and the water box. Since the tubes are made of bare metal and have long, narrow paths for protective current, it is not possible to protect the tube metal with cathodic protection more than a few tube diameters past the tubesheet. Therefore, the tube material needs to be inherently corrosion resistant, and the most noble metal in the system.

If all the materials in the system were highly corrosion resistant and of the same material, no dissimilar metal corrosion cells would exist and a cathodic protection system would not be necessary. Generally, however, it has been more economical to use metals for the tubesheet and water box that are less noble than the tube material and to protect these less noble metals with cathodic protection.

The existing condenser water box system at the Intermountain Generating Station consists of copper-nickel tubes, aluminum bronze tubesheets, and carbon steel water boxes. The existing tubesheet and water boxes are protected with a galvanic anode cathodic protection system. With the selection of a more noble tube material of either titanium or stainless steel, a galvanic anode system will be unable to overcome the more severe dissimilar metal corrosion cell at the tube to tubesheet interface; therefore, an impressed current cathodic protection system will be necessary.

The selection of an impressed current system is primarily a function of current demand. For applications where cathodic protection current requirements are high, impressed current systems are more economical and more practical. A condenser water box system generally has the tube, the tubesheet, and the water box all in metal-to-metal contact with one another. When these metals are all metallically connected, a cathodic protection system supplies current to all of these metals even though its intended function is to protect the less noble metals. In fact, the majority of the current from a cathodic protection system goes to the areas of greatest potential difference and greatest surface area, which is the tube material. Therefore, the selection of more noble tube materials correspondingly increases the cathodic protection current requirements. Similarly, the selection of a more noble tubesheet material would increase the current requirement, assuming the water box material did not change. Therefore, any change of tubes to a more noble tube metal or change to a more noble tubesheet material would increase cathodic protection current requirements, necessitating an impressed current type cathodic protection system.

The estimated capital cost of cathodic protection systems for each unit would be approximately $200,000. The cathodic protection systems would include eight automatic potential controlled rectifiers with appropriate monitoring and control to prevent hydrogen embrittlement damage to the tubes. Anode materials would be selected to provide a 15-year service life. The cost of the cathodic protection systems would not vary appreciably with selection of titanium or stainless steel tubes.

Aluminum bronze tubesheets have been used in numerous applications with all the tube materials under consideration with good results. Aluminum bronze should provide a good tube to tubesheet joint if the tubes are installed and rolled properly.

Based on the delivery schedule, potential installation schedule impacts, technical problems with fabrication and installation, and the successful history of aluminum bronze tubesheets with the alternate tube materials under consideration, it is recommended that the existing tubesheet be used.

4.3.2 Uplift Analysis

Each condenser shell is supported on four foot pads and each foot is restrained with eight 2-inch 4.5 TPI foundation bolts. The north end of the condenser has a maximum uplift of 251 kips at each foot while the south end has a maximum uplift of 466.5 kips at each foot which is considered the maximum permitted for the bolting provided.

A changeover to any lighter tubing than the 20 BWG 90-10 and 70-30 Cu Ni tubing will result in equally distributing the uplift forces to each of the four sets of foundation bolts at the base of each hot well. The existing tube weight calculated to include the maximum 0.003-inch wall thickness plus tolerance is 249,860 pounds.

The uplift analysis results are shown in Table 4-5.

With the alternate tube selections installed, the south ends of the condenser shells would need additional hold-down capability to absorb the effects of the tubing weight reductions. These amount to 43 kips at the center line of the south end feet for the stainless steel tubes and 77 kips for the titanium tubes. To accomplish this additional hold-down capability anchor bolts would be installed through the south end feet.

4.3.3 Tube Support Spacing

None of the four selected alternate tube materials indicate the requirement for additional tube support or staking to prevent tube vibration. In the early stages of the original condenser design, an additional support plate was added to give a total of 12 support plates per tube bank. The support plates are spaced on 35-inch centers with 35.5-inch end spans.

The maximum recommended spans for this condenser using The Heat Exchange Institute guidelines are shown in Table 4-6.

The existing support spacing is considered acceptable for all materials being considered based on these results.

4.3.4 Structural Analysis

Titanium tubes with 2-1/16 inch thick aluminum bronze tubesheets on the LP and HP shells were evaluated. With the 1/4-inch corrosion allowance deducted from the thickness these tubesheets are satisfactory. One of the tubesheets actually supplied has a thickness of 1.954 inches in one area and with the 1/4-inch thickness reduction shows a tubesheet maximum stress of 16,400 psi. The material has a minimum yield of 30,000 psi and tensility of 70,000 psi, which is satisfactory.

TABLE 4-5. UPLIFT ANALYSIS RESULTS

Tube Material	Total Weight per Shell pounds	Weight Loss per Shell pounds	Resultant Uplift Forces North End kips per foot	South End kips per foot
29-4C	164,380	85,480	272.4	487.9
AL-6XN	173,870	79,990	270.0	485.5
Sea-Cure	164,970	84,890	253.2	487.7
Titanium	96,730	153,130	289.3	504.8

TABLE 4-6. ALLOWABLE TUBE SUPPORT SPACING

Material	Maximum Intermediate Span inches	Maximum End Span inches
20 BWG 90-10	38.5	42.2
20 BWG 70-30	40.4	45.5
22 BWG AL29-4C	42.0	46.0
22 BWG AL-6XN	41.0	46.0
22 BWG Sea-Cure	41.0	46.0
22 BWG Titanium	35.0	39.3
Existing Span	35.0	35.5

The pull-out load of 1,200 pounds is lower than the joint strength of 2,500 pounds.

Based on the LP and HP stress calculations for titanium tubes, the resultant tubesheet stresses using 29-4C, AL-6XN, and Sea-Cure tubes are lower than for the original design.

The tube pull-out load for these stainless steel tube selections is 1,200 pounds per tube which is well below the 1,750-pound average holding power shown by test results on these materials. If the entire thickness of the tubesheet is used in the calculations (without subtracting the 1/4-inch corrosion allowance), the load on the peripheral tubes is even lower.

The intermediate pressure shell has 1-1/2 inch thick aluminum bronze tubesheets. Analysis of these tubesheets in combination with either the titanium tubes or stainless steel alternatives results in the same conclusions as for the LP and HP condensers except that, in all cases, the stresses are lower in both the tubesheets and tubes.

5.0 EVALUATION OF ALTERNATE TUBE MATERIAL

The following articles compare the additional aspects (not covered in other sections of this study) of each tube material alternative that should be considered when evaluating the most appropriate material for the Intermountain Generating Station.

5.1 COST ANALYSIS

The total evaluated cost of each material for both units including auxiliary cooling water heat exchangers is shown in Table 5-1. These costs are from the Replacement Condenser Tube Bid Evaluation.

The equivalent capital investment of operating costs due to each material's impact on cycle heat rate and condensate pump flow rate is shown in Table 5-2. These costs are based on the performance evaluation results from Section 4.2.

Other cost considerations are the protective tubesheet coatings and impressed current cathodic protection costs discussed in Subsection 4.3.1.

5.2 OTHER CONSIDERATIONS

- Delivery Schedule--All tube materials quoted can be delivered in such a time frame to comply with the unit outage dates being considered.
- Corrosion Resistance--The 90-10 and 70-30 copper-nickel tubes have experienced pitting attack at the Intermountain Generating Station. Titanium is the most noble alloy; therefore, it has the best properties of overall corrosion resistance followed by AL-6XN and then Sea-Cure and 29-4C. However, titanium and the stainless steel alloys considered all have excellent general corrosion resistance characteristics.
- Past Performance--As stated above, the copper nickel alloys have proven unacceptable at the Intermountain Generating Station. Titanium has proven to be the most reliable material in past

TABLE 5-1. COMPARATIVE COST EVALUATION

	90-10 Cu Ni	70-30 Cu Ni	Alloy 29-4C	AL-6XN	Sea-Cure	Titanium
	$	$	$	$	$	$
Total Evaluated Cost	4,547,864	6,060,082	No Quote	7,485,037	6,941,093	6,769,259
Differential Total Evaluated Cost	*	*	No Quote	715,778	171,834	Base

*Not technically acceptable.

TABLE 5-2. EQUIVALENT CAPITAL INVESTMENT OF OPERATING COSTS--BOTH UNITS

	90-10 Cu Ni $1,000	70-30 Cu Ni $1,000	Alloy 29-4C $1,000	AL-6XN $1,000	Sea-Cure $1,000	Titanium $1,000
Fuel	Base	2,060	4,300	5,190	2,730	4,300
Energy	Base	Base	90	90	90	90
Demand	Base	1,280	2,730	3,320	1,710	2,730
Total	Base	3,340	7,120	8,600	4,530	7,120

performance with respect to corrosion resistance. Again the stainless steels have performed quite well but have not been in use as long as titanium.

- Experience of Tube Material with Existing Materials--As discussed in Subsection 4.3.1 of this study, industry experience has shown that all materials considered have good overall compatibility with aluminum bronze tubesheets and carbon steel water boxes, when appropriate coatings and cathodic protection systems were maintained.
- Installation--All alternate materials are considered to have good tube-tubesheet joint compatibility with the existing tubesheets when properly installed. However, the copper-nickel alloys are the easiest to roll, and the titanium tubes require the greatest care to achieve a good tube to tubesheet joint.
- Hydriding/Hydrogen Embrittlement--The possibility of causing hydriding or hydrogen embrittlement by overdriving the impressed current cathodic protection system exists with titanium, Sea-Cure, and 29-4C. AL-6XN should not exhibit hydrogen embrittlement problems and the copper-nickel alloys are used presently without impressed current cathodic protection and are immune to hydrogen embrittlement.

6.0 CHEMICAL TREATMENT CONSIDERATIONS

6.1 OBJECTIVE

The objective of this section is to address the chemical treatment of the circulating water system to date, and the treatment required in the future, to prevent scale formation, and minimize corrosion attack on the condenser tubes.

6.2 CIRCULATING WATER CHEMICAL FEED DESIGN

The design of the Circulating Water Chemical Feed System was based on providing protection of the Circulating Water System and of the condensers against excessive scaling and corrosion, and for the control of biological slime and algae. The Circulating Water Makeup Treatment System provides for clarification and lime softening of the raw water from the Sevier River. This treatment reduces cooling tower blowdown requirements and the potential for scaling of the condenser tubes. Lime softening also serves to disinfect the water which aids in control of microbiological growth.

The Circulating Water Chemical Feed System feeds sulfuric acid, an organic phosphate scale inhibitor, tolyltriazole, and chlorine to the Circulating Water System. Sulfuric acid is fed at a controlled rate for alkalinity reduction in order to control the calcium carbonate scaling tendency of the circulating water. The circulating water at the Intermountain Generating Station is controlled within a pH range of 7.6 to 8.0, as reported in S. G. Chapman's letter to B. E. Blowey dated January 12, 1988. In this pH range, copper alloys are considered to be relatively stable. This is verified by coupon tests which indicate general corrosion rates of less than 0.2 mils per year on 90-10 copper-nickel. To further inhibit scale deposition, an organic phosphate scale inhibitor is fed as a sequestering agent. Tolyltriazole is fed as a copper corrosion inhibitor. An Amertap condenser tube cleaning system is also used to prevent scale buildup in the condenser tubes.

Shock chlorination is employed as required to minimize biofouling of heat transfer surfaces, and to minimize aquatic growth on the towers and in the piping. In the above referenced letter, IPSC reports daily one-time chlorinations to a free chlorine residual of 0.1 ppm during winter conditions, and twice a day chlorinations during summer conditions. IPSC reports low biological activity in the circulating water since commercial operation began, proving the effectiveness of chlorination.

The treatment program employed is consistent with industry practice for circulating water systems operating at high cycles of concentrations.

A change in condenser tube materials from 90-10 copper-nickel to another material is not expected to change the circulating water chemical feed requirements significantly. Sulfuric acid and a scale inhibitor will still be required for pH control and the prevention of scale formation. The scale inhibitor formulation may require some modification to be more compatible with the selected material. Shock chlorination will also be continued for the control of biological growth. The chlorination requirements, frequency of chlorination and concentration, will likely be greater for noncopper alloy condenser tube materials. This is because the copper alloys exhibit greater biofouling resistance than do the other candidate condenser tube materials. Tolyltriazole feed will no longer be required for copper corrosion inhibition if copper alloys are excluded. However, depending on the tube material selected, another corrosion inhibitor may be substituted.

The Circulating Water Makeup Treatment System was designed based on USGS water quality data reported for the Sevier River near Lynndyl, Utah for the 17 consecutive water years October 1961 to September 1962 through October 1977 to September 1978. From this data, the mean values and standard deviation for each constituent were determined. The monthly values were ranked and exceedance probabilities were determined. The 10 percent exceedance probability values were used as a basis for equipment design. This would mean that the values of a constituent could be expected to be exceeded 10 percent of the time, or 36.5 days per year. The water can be characterized as a high solids surface water.

Table 6-1 compares the Circulating Water Makeup Treatment System design water analysis with an actual analysis of water from the DMAD Reservoir taken January 4, 1988. The comparison on Table 6-1 shows the actual water to be in relative agreement with the design water analysis. There are indications from the data provided by IPSC, however, that excursions of some of the constituents do occur in some of the streams feeding the DMAD Reservoir. These excursions are attributed primarily to agricultural runoff. The most notable among these is the Chicken Creek stream. Water data for the Chicken Creek stream is provided in Table 6-2. Of all streams feeding the DMAD Reservoir, the Chicken Creek is highest in total hardness and chlorides. Such contributions cause rapid excursions in the quality of circulating water makeup. The effects of variations on the corrosiveness of the circulating water are not fully understood.

TABLE 6-1. COMPARISON OF THE DESIGN WATER ANALYSES OF THE CIRCULATING WATER MAKEUP TREATMENT SYSTEM WITH DMAD RESERVOIR WATER SAMPLE TAKEN JANUARY 4, 1988

Constituent	Concentration (mg/l) Design Water Analysis	Concentration (mg/l) DMAD Reservoir January 4, 1988
Calcium as Ca	95	86
Magnesium as Mg	106	114
Sodium as Na	346	--
Potassium as K	9	--
Bicarbonate as HCO_3	359	--
Sulfate as SO_4	447	390
Chlorides as Cl	480	504
Silica as SiO_2	20	15.1

TABLE 6-2. WATER DATA FOR CHICKEN CREEK AS PROVIDED BY IPSC

Constituent	Concentration (mg/l) October 8, 1987	Concentration (mg/l) January 4, 1988
Calcium as $CaCO_3$	688	808
Magnesium as $CaCO_3$*	1,056	1,021
Chlorides as Cl	680	649
Sulfate as SO_4	--	1,412
Silica as SiO_2	9.6	15.0

*Values shown for Magnesium are the differences between values reported for total hardness and those reported for calcium.

APPENDIX A
DOCUMENT LIST

APPENDIX A
DOCUMENT LIST

A listing of documents and reports received and considered in this study is included in this appendix.

(1) "Report on Analysis of Possible Corrosion of 90/10 Copper Nickel Tubes for Unit 1," by C. H. Pitt, Professor of Metallurgy, University of Utah, dated April 22, 1985.

(2) Letter report from F. Higham of Phelps Dodge dated August 23, 1985, transmitting a report from L. Caruso dated August 19, 1985, regarding Unit 2 condenser tube evaluation.

(3) "Failure Cause Analysis: Accelerated Localized Corrosion of 90-10 and 70-30 Cu-Ni Condenser Tubes" prepared by E. F. Conley of Heat Exchanger Systems, Inc., for Intermountain Power Service Corp., Intermountain Power Project, Unit 1, received by Black & Veatch May 6, 1987.

(4) "Metallurgical Examination, Unit 1 Condenser, Intermountain Generating Station," Report No. C-4335 dated June 16, 1987 by LADWP Laboratory and Technical Services Section.

(5) "Preliminary Results on Pitting in 90-10 Cu-Ni Condenser Tubes in IPP Unit 1," dated July 8, 1987 from G. S. Was of University of Michigan, received July 24, 1987, B&V File No. 9255.62.1204.02.

(6) "Failure Cause Analysis: Accelerated Localized Corrosion of 90-10 Cu-Ni Condenser and Component Cooling Water System Heat Exchanger Tubes, Volume 1 of 2; Metallographic and Spectroscopic Analyses," prepared by Heat Exchanger Systems, Inc., for Intermountain Power Service Corp., Intermountain Power Project, Unit 1, Draft, received by Black & Veatch July 24, 1987.

(7) Structure Probe Technical Report 80339, "Research Study of Coating in Copper/Nickel Tube using Auger Electron Spectroscopy," prepared by A. W. Blackwood and A. M. Hirt, dated September 28, 1987.

(8) Letter report dated September 30, 1987 from T. B. VanderWood, Ph.D of McCrone Associates - Atlanta, to J. K. Wakamatsu reporting the results of the analysis of the corroded condenser tube received September 17, 1987.

(9) Letter report dated October 6, 1987 from S. Sheybany, Ph.D of Scanning Electron Analysis Laboratories, Inc. to J. K. Wakamatsu regarding examination of corrosion products from inside a condenser tube.

(10) "Condenser Tube Pitting Corrosion Review Report," prepared by LADWP, Mechanical Engineering Section, October 23, 1987.

(11) Technical Report 80358 "Research Study of Copper/Nickel Alloy Tubes Using Metallography, Scanning Electron Microscopy, Energy Dispersive X-ray Spectroscopy, and Scanning Auger Microprobe Techniques," by Structure Probe, December 10, 1987.

(12) "Analysis of Corroded Copper-Nickel Condenser Tubes - Unit 1," McCrone Associates - Atlanta, December 22, 1987.

(13) Technical Report 80361 "Research Study of Three Copper/Nickel Alloy Tubes Using Metallography, Scanning Electron Miscroscopy, Energy Dispersive X-ray Spectroscopy, Scanning Auger Microprobe, and X-ray Diffraction Techniques," by Structure Probe, December 29, 1987.

(14) Onsite Reservoir Water data on total hardness, calcium, and chlorides from November 1986 to December 1987.

(15) Plot of cycles of concentration and ppm chlorides from December 1, 1986 to January 5, 1988. DMAD Reservoir/Sevier River Water Quality data from 1987 and 1988 and November 1953 to January 1967.

(16) Letter dated January 12, 1988 from S. G. Chapman of IPSC to B. E. Blowey of LADWP titled "Condenser Tube Pitting at IGS.," with seven appendices. The appendices include the following.

(a) Eddy Current Test Data Summary of November 12, 1987.
(b) Silicate scale control guidelines curve for circulating water operation by Calgon.
(c) Great Sevier Lake Water Chemistry data for July 4, 1986 and December 13, 1987.
(d) Unit 2 Circulating Water Quality data for November 10, 1986 to November 10, 1987, Unit 1 Circulating Water Quality data from May 21, 1985 to March 29, 1986, Solids Contact Basin 1A Inlet and Outlet Water data from June 19, 1987 to September 27, 1987, Solids Contact Basin 1B Inlet and Outlet Water data from November 13, 1986 to September 27, 1987.
(e) Paper by Calgon "Copper Corrosion in the Utility Industry," by B. P. Boffardi.
(f) Report dated October 2, 1985 on Cooling Tower Treatment Formulations Testing done by IPSC from March 1, 1985 to August 1, 1985.
(g) Data on Calgon test of tolyltriazole with 90/10 and 70/30 copper-nickel tubes at 10 cycles of concentration and a corrosion test on 70/30, 90/10, and AL-6XN.

(17) Letter report dated January 12, 1988 from C. Bowers of McCrone Associates - Atlanta, to J. K. Wakamatsu enclosing the results of the analyses of three corroded condenser tubes received December 11, 1987.

(18) Letter dated January 20, 1988 from B. E. Blowey to S. G. Chapman of IPSC titled "Condenser Tube Examination--Intermountain Generating Station (165) Units 1 and 2."

(19) "Condenser Tube Pitting Corrosion Review Report" transmitted by memorandum dated January 25, 1988 from T. H. McGuinness to D. Hyska.

(20) "Eddy Current Inspection of a 10 Percent Sample of Tubes Installed in the Main Steam Condenser, Units 1 and 2, November-December 1987" report dated January 26, 1988 by Heat Exchanger Systems, Inc.

(21) "Test Plan - Condenser Tube Materials Evaluation (Revised Drafts)" received February 4, 1988, prepared by Heat Exchanger Systems, Inc.

(22) Letter report dated February 9, 1988 from W. J. Bow of Foster Wheeler Energy Corporation to K. Trout of Black & Veatch regarding Intermountain Power Agency, Unit 1 Condenser Engrg. Study.

(23) Letter report dated February 12, 1988 from E. F. Conley, Heat Exchanger Systems, Inc., "IPSC Condenser Tube Materials Evaluation Test Program--Initial Report of Results."

APPENDIX B

TELEPHONE MEMORANDA

APPENDIX B
TELEPHONE MEMORANDA

The telephone memoranda supporting the telephone survey in Section 3.2 are included in this appendix.

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 09255
B&V File 62.1204
January 28, 1988
1:30 p.m.

To: Burt Dietz/Tom Bursett
Company: Olin Corporation
Phone No.: 618-258-2879

Recorded by: R. R. Helling

Mr. Dietz and Mr. Bursett could not think of any utilities that have replaced 90/10 Cu-Ni condenser tubes in freshwater, cooling tower service with another copper based alloy. In fact Mr. Bursett thought it rare for any 90/10 to require replacement unless some unusual condition may have occurred. Mr. Bursett suggested that Olin be provided a sample of the condenser tubes for analysis, free of charge. Olin expressed interest in knowing the failure mechanism.

Mr. Bursett suggested B&V talk to John Tsou of EPRI (415) 855-2220, although he noted that John Tsou's advice will be not to replace with Cu-Ni.

B&V obtained the following descriptions of the various alloys listed in Olin's installation list.

- 194 - High strength modified copper. This material is not used much any more due to many problems in seawater service. Used in freshwater applications only.
- 706 - 90/10 Cu-Ni
- 715 - 70/30 Cu-Ni
- 722 - 85/15 Cu-Ni plus chrome. This material has excellent corrosion resistance, and is good for seawater service.

Mr. Dietz will have Tom Foster, who has discussed the IPP tube problem with Paul Arnerich, contact R. Helling for further discussion on this problem.

pag

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 09255
B&V File 62.1204
January 29, 1988
8:15 a.m.

From: John Thackray
Company: Trent Tube
Phone No.: 414-642-7321

Recorded by: R. R. Helling

Mr. Thackray returned my call of January 28, 1988 to Mr. Hank Hubbell of Trent Tube. Neither Mr. Thackray nor Mr. Hubbell were able to name any utilities that have replaced 90/10 Cu-Ni tubes in freshwater, cooling tower applications with Sea-Cure.

Mr. Hubbell named Niagara Mohawks Nine Mile Point Nuclear Station as having replaced 90/10 tubes in the air removal section with Sea-Cure. This plant was on freshwater, but it was not known if it had a cooling tower.

Mr. Thackray will telecopy Trent Tube's installation list with contacts and telephone numbers. A similar listing was provided Paul Arnerich of LADWP.

pag

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 9255
B&V File 62.1204
January 29, 1988
3:20 p.m.

To: Mike Woods (Engineer)
Company: Navajo Plant - SRP
Phone No.: 602-645-8811, Ext. 242

Recorded by: R. R. Helling

The Navajo Plant uses lake water (Colorado River water) as makeup to its recirculating water cooling system. The 90/10 Cu-Ni tubes in Unit 3 were replaced in 1986 with 20 gage AL-6XN tubes. The decision to use AL-6XN was based in part on the good performance at the Mojave Plant (which used AL-6X) and at APS-Cholla. Condenser modifications were not desired, therefore titanium was ruled out. A vibration analysis showed that no condenser or support plate modifications were needed with the AL-6XN tubes. Also, the Navajo chemical cleaning consultant indicated that AL-6XN (austenitic) would be more resistant to hydrofluoric acid than would Sea-Cure (ferritic). Hydrofluoric acid is used for occasional condenser tube cleaning.

Equipment to do the tube replacement, as well as supervisors, were leased from Harris Tube Pulling Company; otherwise, Navajo did the retubing themselves. The Harris equipment would pull the tube out and simultaneously cut it into 5-inch pieces. About 25,000 tubes were retubed in 28 days, working around the clock. Harris subsequently bid on and was awarded the scrap metal as well.

The existing silicon bronze tubesheet was used on tube replacement. Allegheny Ludlum recommended replacement of the tubesheet with AL-6XN, and Mr. Woods agreed with the recommendation, but the cost of a AL-6XN tubesheet was prohibitive. The tubesheet was not initially coated nor was it coated upon tube replacement. Impressed current cathodic protection was added for tubesheet protection on tube replacement. The condenser waterbox is coated. No tube cleaning system is used on Units 2 and 3; however, Unit 1 uses an Amertap tube cleaning system. Mr. Woods indicated that the replacement tubes are providing excellent performance, although no technical analysis of their condition has been performed.

The cause of failure of the original tubes has been attributed to underdeposit corrosion caused by tenacious silica deposits. The corrosion was found primarily in the hottest zones of the condenser, usually extending the entire length of the tubes. The Navajo plant chemist characterized the circulating water as follows.

Black & Veatch

TELEPHONE MEMORANDUM

Conductivity	8,500-12,600 mhos
pH	7.2-7.5
M Alk	48-80 ppm
Ca	350-700 ppm
Mg	1,100-1,250 ppm
TH	1,700-2,150 ppm
Cl	550-910 ppm
SO_4	3,700-6,800 ppm
SiO_2	90-150 ppm

Mr. Woods indicated that the 90/10 condenser tubes on Unit 2 will be replaced with AL-6XN starting about March 12, 1988. Personnel from IPP and LADWP are invited to observe the retubing operation if desired.

blk

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project	B&V Project 9255
Intermountain Generating Station	B&V File 62.1204
Condenser Tube Failure	Feb. 1, 1988
	9:55 a.m.

To: Steve Schulder/Ken Cramelett
Company: Baltimore Gas & Electric-Wagner/Brandon Shores
Phone No.: 301-787-6942 / 301-787-5588

Recorded by: R. R. Helling

The Brandon Shores Plant uses brackish water as makeup to its recirculating water cooling system. The unit went commercial in May 1984. The condenser has 70/30 Cu-Ni tubes in the air removal section, with the remainder of the tubes being 90/10 Cu-Ni. The tubes are scheduled to be replaced late this year, due to severe pitting. The cause of the failure has not been determined but BG&E is spending about $1 million researching the problem. A replacement tube material has not yet been determined, pending findings from the research program. Mr. Schulder indicated that tolyltriazole feed was not effective. The Brandon Shores condenser tubesheet had no protective coating nor cathodic protection. The condenser waterbox is coated. A WSA tube cleaning system is used.

The Brandon Shores circulating water was characterized as follows.

Conductivity	30,000-35,000 mhos
pH	8.2-8.4
Ca	480 ppm max as $CaCO_3$
Mg	1,200 ppm max as $CaCO_3$
TH	1,000 ppm as $CaCO_3$
Na	10,700 ppm
Cl	18,000 ppm
SiO_4	3,000 ppm
SiO_2	13 ppm

The two Calvert Cliffs' units operate on once-through seawater. Each unit had its 70/30 Cu-Ni condenser, tubes replaced. One unit was replaced with AL-6X; the other was replaced with titanium tubes. Atlantic Condenser Services did the retubing jobs.

blk

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 9255
B&V File 62.1204
February 1, 1988
2:24 p.m.

To: Tom Walsh
Company: APS-Cholla
Phone No.: 602-288-3381, Ext. 464

Recorded by: R. R. Helling

The Cholla Plant uses lake water as makeup to its recirculating water cooling system. Both Unit 3 and Unit 4 condensers had 70/30 Cu-Ni tubes in the air removal and steam impingement sections, and Admiralty brass in the remainder of the condenser. The tubes in Unit 4 were replaced about 6 months ago and in Unit 3 they were replaced last week. AL-6XN was used as the tube replacement material for both units. The decision to use AL-6XN was based on the good experience and history reported by the utility industry, and on economic evaluation. The original Muntz metal tubesheets were used on both tube replacements. Both units have impressed current cathodic protection for the uncoated tubesheets. The water boxes are coated with a coating manufactured by ConChem. Mr. Walsh noted that Plasticure manufactures an epoxy coating that has provided excellent service at Four Corners. The coating system costs about $20 per square foot.

The retube work was done in the field, by Harris Tube Pulling on Unit 4 and by Atlantic Nuclear on Unit 3. Both outfits are highly recommended. No condenser modifications were necessary to do the retubing. Unit 4 had 19,000 (40 ft length) tubes replaced, and Unit 3 had 16,000 (36 ft length) tubes replaced. Mr. Walsh did not know the size of the tubesheets. Mr. Walsh advised that when new tubes are ordered that 1/2 inch be added to the overall length to accommodate for tubesheet warpage.

Mr. Walsh indicated that for both units more than half the tubes had lost more than 80 percent of the tube wall. A failure mechanism for the tubes was not known. Neither unit has a continuous tube cleaning system.

blk

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 9255
B&V File 62.1204
February 1, 1988
3:36 p.m.

To: Steve Patera
Company: Timet
Phone No.: 214-641-4410

Recorded by: R. R. Helling

Mr. Patera called to advise of the following plants that have had 90/10 Cu-Ni condenser tubes replaced with titanium tubes. To the best of Mr. Patera's knowledge, these are all freshwater plants.

Company	Station	Year
Narragansett Electric Co.	South St.	1973
Bethlehem Steel Co.	Sparrows Pt.	1974
Houston Lighting & Power Co.	Robinson No. 1	1975
Houston Lighting & Power Co.	Robinson No. 2	1975
Houston Lighting & Power Co.	Robinson No. 3	1976
Gulf States Utilities	Sabine River No. 2	1977
Gulf States Utilities	Sabine River No. 3	1977
Pacific Gas & Electric Co.	Diablo Canyon No. 1	1985
Pacific Gas & Electric Co.	Diablo Canyon No. 2	1986
Potomac Electric Co.	Chalk Point No. 2	1986
Texas Utilities Gen. Co.	Comanche Peak No. 1	1988
Texas Utilities Gen. Co.	Comanche Peak No. 2	1989

blk

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 9255
B&V File 62.1204
February 1, 1988
3:40 p.m.

From: Jerry Larson
Company: KCP&L - Iatan
Phone No.: 816-386-2289

Recorded by: R. R. Helling

The Iatan Station uses Missouri River water for once-through cooling. The condenser has 70/30 Cu-Ni in the air removal and steam impingement sections, and 90/10 Cu-Ni in the remainder of the condenser. The tubesheet is Muntz metal. The unit has been in service since May 1980. KCP&L is considering replacing the tubes in 1990-91. Presently, 90/10 Cu-Ni and stainless steel are being considered as replacement materials.

Severe erosion, caused by sand and silt in the cooling water, has been experienced at the tube inlets. Four years ago tube inserts were installed which moved the erosion problem from the tube inlet to the end of the inserts. All inserts have since been removed and the tubes have been coated with an epoxy coating for approximately 30 inches. Over-rolling on initial installation into the tubesheet also caused thinning of the outlet tube walls causing them to shear in service.

The tubesheet is not coated. Mr. Larson was not sure whether the condenser was cathodically protected. The waterbox is coated. The tubesheet measures 10 ft 11 in. by 9 ft 5 in. and has 23,368 tubes in four sections.

blk

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 9255
B&V File 62.1204
Feb. 3, 1988
11:42 a.m.

From: Ivan Francin
Company: Allegheny Ludlum
Phone No.: 412-226-5049

Recorded by: R. R. Helling

Mr. Francin mentioned the following utilities as having installed AL-6X or AL-6XN tubes in replacing 90/10 Cu-Ni tubes.

Mohave (AL-6X); no contact known.

Belfont Nuclear Station; contact John Stellern at 615-632-4597, TVA-Knoxville.

Shawnee Station; contact Steven Merry at 615-751-2930, TVA-Chattanooga.

APS-Cholla; contact Dan Nass.

Mr. Francin mentioned George Moller, 213-316-0023, a consultant on condenser failures, as being a good source of information.

Mr. Francin developed the AL-6XN alloy.

The AL-6XN is a modified version of the AL-6X and contains 0.2 percent nitrogen. The nitrogen makes the alloy a tougher material and improves its pitting resistance. Other constituents of the AL-6XN and AL-6X alloys are 21% chrome, 24.5% nickel, 6.3% molybdenum, in an iron base. The AL-6XN has been commercially available about 3 to 4 years and has replaced AL-6X.

blk

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project
Intermountain Generating Station
Condenser Tube Failure

B&V Project 9255
B&V File 62.1204
Feb. 4, 1988
2:30 p.m.

To: Steven Merry
Company: TVA
Phone No.: 205-437-9409

Recorded by: R. R. Helling

Mr. Merry provided some general comments and then discussed condenser tube problems at the Paradise Station and the tube replacement at Widow's Creek. In general, TVA has standardized on the use of admiralty brass where low flow conditions exist or where there is a high possibility for fouling. In several TVA plants AL-6X tubes have been used to "crown" the condenser for impingement protection and also in the air removal section with the remainder of the condenser being admiralty.

Paradise Station

The Paradise Station is located in strip mining country and draws its cooling water from the Green River. Cooling towers are used, but Mr. Merry did not know to what degree the water is cycled. The station has had an Asiatic clam problem and a lot of dead fish were found in the condenser. No mussel problem exists.

The Admiralty tubes at Paradise Station failed due to ammonia attack and were replaced about 4 years ago with 90/10 Cu-Ni. The 90/10 tubes have experienced significant localized pitting problems thought to be caused by sulfide attack and low flow conditions. Eddy current testing has shown pits 50-60 percent through the wall. Inspection of tubes cut out of the condenser have verified the pitting problem.

A complete condenser replacement is being considered for the Paradise Station. The condenser will be redesigned to solve a poor distribution problem. Materials being considered are 85-15 Cu-Ni, Seacure, and AL-6XN. The carbon steel tubesheet is not coated nor is any cathodic protection provided. The waterbox is coated, and is thought to be a coal tar epoxy. The station does have an Amertap tube cleaning system.

Widow's Creek

The 30 year old 90/10 Cu-Ni tubes at Widow's Creek are being replaced with 90/10. About 20 tubes will be 85/15 Cu-Ni installed as part of a TVA test program. About 20 of the 90/10 Cu-Ni tubes will be furnished with orifices to simulate low flow conditions and thereby intentionally pit the tubes. TVA is hoping to have some test data by the Widow's Creek June 1989 outage to aid in selecting a material for the Paradise Station.

Widow's Creek is a once-through freshwater plant. The original tubesheet is Muntz metal and is in good condition. The tubesheet was not coated nor was any cathodic protection used. No plans are being made to add cathodic protection during the retube job, but TVA is considering coating the tubesheet. No coating material has been selected. A manual Amertap tube cleaning system is used at the plant and modifications are being considered to automate the system.

TVA is doing the retubing themselves using equipment from Harris Tube Pulling Co.

blk

Black & Veatch

TELEPHONE MEMORANDUM

Intermountain Power Project	B&V Project 9255
Intermountain Generating Station	B&V File 62.1204
Condenser Tube Failure	Feb. 5, 1988
	9:57 a.m.

To: Dan Fauber
Company: TU - Comanche
Phone No.: 817-897-4856

Recorded by: R. R. Helling

Comanche Peak is a PWR which uses once-through brackish cooling water. The plant has only operated for the last 6 months while undergoing performance testing. An operating license has not yet been awarded.

The original 90/10 Cu-Ni were replaced in 1985 with titanium. The original uncoated carbon steel tubesheet was replaced with a new carbon steel/ titanium clad tubesheet. The tube replacement was not corrosion related, but one of concern about copper leaching into the cycle water. Mr. Fauber indicated that they did have some problems with their tube to tubesheet seals; a lot of air inleakage was experienced during vacuum testing. Zachary Construction did the modular tube replacement work. About 50,000 tubes in all were replaced.

No cathodic protection was originally furnished on the condenser, but TU is looking for a vendor to design a system. I advised that B&V has expertise doing cathodic protection design and might be interested in the work. Mr. Fauber indicated that Mr. Craig Harrington, 817-897-6705, should be contacted to discuss the work.

A Speco epoxy coating (identification unknown) was originally installed in the condenser waterbox and failed (failure mechanism unknown). The original coating was replaced with another Speco coating, called Speeflex. No condenser tube cleaning system is installed on the unit.

Mr. Fauber also mentioned that the seal water heat exchanger 90/10 Cu-Ni tubes also failed due to improper wet layup. Mr. Ivan Whitt, 817-897-5687, at TU was named as someone who could provide other instances of 90/10 tube failures.

blk

IP12_003144

Black & Veatch

CONFERENCE MEMORANDUM 513

Intermountain Power Project
Intermountain Generating Station
Cathodic Protection

B&V Project 9255
B&V File 63.0400
June 17, 1988

Meeting held on Tuesday, May 17, 1988, in our office to discuss design of the cathodic protection system for the condenser and heat exchanger retubing project.

Attending:

Los Angeles Department of Water & Power	Ocean City Research	Black & Veatch
Joe Awad	George Gehring	Paul Bannister
Randy Howard		David Becker
John Musto		Russ Helling
Jerry Pruett		Gary Jamison
Vishnu Srivastava		Lou Johnson

1. Black & Veatch (B&V) presented description of the cathodic protection system as currently included in the Owner-review issue of the specification. In addition, B&V presented a description of the monitoring system to be provided under other specifications.

2. The current ratings of the rectifiers as specified were determined to be greater than required. The specifications are to be revised to reduce the current rating specified by 50 percent (e.g. 60A in lieu of 120A). Where commercially available, three phase rectifiers will be specified.

   Rectifiers will be column mounted where practical.

3. In lieu of the specified wet reference electrode cells, dry cells are to be used for both the tubesheet and water box electrodes. Cells are to be silver/silver chloride/seawater type. B&V is to investigate reported failures of a EDI seawater type cut on a Florida Power & Light power generating station.

4. In lieu of the platinum anodes specified, mixed metal oxide coatings are to be used. Such anodes are considered to be stronger and to have a longer life. Anode diameter is to be increased to 3/4 inch diameter for greater strength.

IP12_003145

5. All water box electrodes and anodes are to be mounted with a ball valve to allow on line replacement. Ball valves will be furnished and erected by the condenser retubing contractor.

   B&V will coordinate the design of the fittings to be welded in the water box for the electrodes and anodes.

6. It was noted that the water box temperature exceeds 200 F following a black shutdown. (Note this is not the circulating water temperature, but the temperature in the void left when the circulating water drains to the elevation in the cooling tower basin.)

   B&V is to issue specification addendum requiring components mounted in the condenser water box to be suitable for operation at 210 F.

7. Reducing the anode length projection into the water box from 18 inches to 12 inches was discussed. It was agreed that the 18 inch anode length would still be required to achieve a twelve inch projection because of the ball valves being added.

8. B&V presented the layout of the probe anodes using a three dimensional CAD system to show the relationship to the water box internals.

9. B&V described layout proposed for reference electrodes. One or more tubesheet electrodes would be located to monitor the area closest to anodes and one or more to monitor the area farthest from the anode. These locations would provide operating data on the worst case locations.

10. Los Angeles Department of Water and Power (LADWAP) expressed concern that the monitoring system may cause too many nuisance alarms, which may cause the system to be disabled by operating personnel. B&V maintained that the system was conceptually simple, and that nuisance alarms would be minimized by spreading the alarm band limits as much as possible during checkout. LADWAP indicated it would be desirable to have a log of the reference electrode potentials. B&V agreed to have this information transmitted from the Monitoring System Cabinet to the data logger.

11. B&V advised the anode output current would be adjusted with resistors to achieve, as much as possible, a uniform potential distribution across tubesheet. The control reference electrode would be selected ant the set potential adjusted so that the tube potential does not exceed -0.7 volts at any location. This control can be achieved regardless of which reference electrode is selected as the control reference electrode.

12. B&V will provide LADWAP with the condenser and auxiliary cooling water heat exchanger cathodic protection system operating procedures. Water box electrodes would be placed four to six inches from the tubesheet, as far from the anodes as possible.

THE AM[illegible]CAN SOCIETY OF MECHANICAL ENGINEERS
345 E. 47 St., New York, N.Y. 10017

The Society shall not be responsible for statements of opinions advanced in papers or in discussion at meetings of the Society or of its Divisions or Sections, or printed in its publications. Discussion is printed only if the paper is published in an ASME Journal. Papers are available from ASME for 15 months after the meeting.

Printed in USA.

87-JPGC-Pwr-F

Received from Paul Fulford

cc: PFB
CHF
GGJ
LCJ

CHARACTERIZATION OF TITANIUM CONDENSER TUBE HYDRIDING AT TWO FLORIDA POWER & LIGHT COMPANY PLANTS

J. Paul Fulford
Florida Power & Light Company
Juno Beach, FL

Ronald W. Schutz
TIMET Division, Titanium Metals Corporation of America
Henderson, NV

Robert C. Lisenbey
Florida Power & Light Company
Juno Beach, FL

ABSTRACT

Significant hydriding of titanium surface condenser tubes has been identified at Florida Power & Light Company's St. Lucie 1 and Turkey Point 3 nuclear power plants. Condenser tube eddy current test probe surveys reveal that 3.4% and 1.5% of the St. Lucie 1 and Turkey Point 3 tubes, respectively, were severely hydrided (≥50% through-wall) near either inlet or outlet ends of the condensers. All evidence indicates that the tube hydriding resulted from relatively-high cathodic potentials (> 1 volt SCE) and current densities impressed on seawater side tube surfaces by the impressed current tubesheet/water box cathodic protection systems. Based on a limited number of tube samples for mechanical property evaluation, including tensile, flattening, and hydrostatic pressure tests, a relatively minor effect on properties was revealed. Good tube integrity for continued service was indicated relative to static loads anticipated in situ. The influence of hydriding on tube fatigue life has yet to be assessed. Although no hydride-related tube or tube joint failures have been observed to date at either plant, corrective operating and design measures for each condenser are discussed which have been implemented to thwart further tube hydriding and maximize condenser life.

Presented at the Joint ASME/IEEE Power Generation Conference
Miami Beach, Florida - October 4-8, 1987

INTRODUCTION

Titanium surface condenser tubing has provided reliable, corrosion-free service in Florida Power & Light's (FP&L) Turkey Point and St. Lucie power plants since their installation more than eight years ago. However, a routine condenser waterbox/tubesheet inspection in January 1986 revealed approximately eighty cracked and embrittled protruded outlet tube ends in each of the St. Lucie Unit 1 condensers. Although no associated condenser tube or tube joint leakage was indicated, the embrittled protruding tube ends raised concerns about the actual extent of possible titanium tube damage and the impact on future condenser performance. Metallurgical examination of several tubes subsequently pulled from a Turkey Point Unit 3 condenser revealed measurable tube I.D. side hydriding in the area of the outlet tubesheet, intensifying concerns about possible tube embrittlement.

St. Lucie 1 and Turkey Point 3 are both PWR nuclear plants located on Florida's eastern coast, rated at 840 and 666 MW, respectively. The incentives to fully assess the condition of condenser tubes at these two FP&L plants include: 1) potential liabilities and costs associated with base-loaded nuclear plant unit outages; 2) the vital need for leak-free condensers to avoid chloride-induced damage to steam generators; and 3) the very high replacement costs for surface condensers.

CONDENSER DESCRIPTION/BACKGROUND

Turkey Point 3 - The four shell Turkey Point 3 condensers were constructed in 1966 by Foster Wheeler Co., utilizing 11,800-1.0 inch diameter x 50 feet long tubes per condenser shell. Original tubes were 0.049 inch wall aluminum brass, which were replaced with aluminum brass after several years due to corrosion. These condensers were finally retubed in 1976 with 0.028 inch wall welded grade 2 titanium tubes to eliminate seawater-side erosion-corrosion. The tubesheets are Muntz metal and the waterboxes are coated carbon steel. The cooling medium is concentrated seawater supplied from a closed-loop cooling canal system, providing inlet cooling temperatures of 75-90°F, with tubesheet seawater velocities of 7-10 ft/sec. Shellside inlet steam temperature is approximately 120°F.

The cathodic protection system in each waterbox consisted of a manually-controlled rectifier energizing fifteen, 4 inch diameter x 80 inch long graphite rod anodes evenly distributed around the waterbox shell. Several of the anodes were located as near as 6-8 inches away from the tubesheet face. Output currents of 20 amps for the (coated tubesheet) inlet waterboxes and 50 amps for the (uncoated tubesheet) outlet waterboxes were applied to attain an impressed potential of -900 mV relative to a remotely-positioned, temporary $Cu/CuSO_4$ reference cell.

St. Lucie 1 - The four shell St. Lucie 1 condensers were designed by Westinghouse Corporation and built in 1970. Original tubes consisted of 11,500 -0.875 inch diameter x 0.049 inch wall x 50 feet long aluminum brass tubes per condenser shell, installed in Muntz metal tubesheets. In 1979, these condensers were retrofited with aluminum bronze tubesheets and 0.028 inch wall grade 2 titanium tubing due to seawater corrosion problems. The tubeside cooling medium, used to condense shellside steam at 120°F, is fresh seawater (68-80°F) with tubeside flow velocities of 7-10 ft/sec.

The St. Lucie 1 waterbox cathodic protection systems consisted of manually-controlled rectifiers which powered nine silicon iron button anodes per water-box, distributed evenly around each waterbox shell. Seven additional anodes were installed adjacent to and within 1 foot of each tubesheet at the time the condenser was retubed with titanium. Rectifier current output varied from 45 amps in inlet waterboxes to 90 amps in the outlet waterboxes, applying the same -900 mV impressed potential criteria discussed previously. Again, inlet tubesheets were coated and outlet tubesheets were not.

INVESTIGATION

Activity encompassed both non-destructive eddy current (ECT) probe surveying of condenser tubes in situ, and destructive testing of full length tube samples pulled from affected condensers. Since no proven NDT technique for measuring the extent of titanium tube hydriding was commercially available, an ECT method was developed. This method was subsequently qualified on hydrided tube samples by correlation with results of tube metallurgical examination. One-hundred percent of both inlet and outlet side tube ends at both plants were ECT probe (absolute mode) tested within a distance of three feet into the condenser steamspace.

Destructive tube sample evaluation consisted of various standard mechanical tests including tube tensile tests per ASTM Spec E8, tube flattening and reverse flattening tests per ASTM Spec B338, and hydrostatic pressure tests. Additional destructive tube evaluation included residual hoop stress analysis, analysis of hydrogen content via the hot vacuum extraction method, and microstructural examination of polished and etched mounted tube sections. Microstructural examination of sectioned tubes proved to be an especially useful technique since it provided a definitive indication of distribution, morphology, and relative quantity of titanium hydride phase present.

Strain gages were installed on St. Lucie 1 and Turkey Point 3 condenser tubes O.D. surfaces near condenser tubesheets in multiple locations to collect operating tube frequency and cyclic stress information. This would provide basic parameters for laboratory cantilever tube fatigue tests to identify any possible effects of tube hydriding on tube fatigue life. However, these high cycle tube fatigue tests have not yet been completed and, thus, are not included in this paper.

The original condenser cathodic protection systems installed in these plants were incapable of monitoring accurate steady-state tubesheet potentials, due to rather infrequent reference potential measurements made from remote waterbox locations. To obtain a more accurate potential profile across the tubesheet, and identify possible correlation between tubesheet location and tube hydriding, newly-developed Ag/AgCl reference electrodes were mounted in key locations directly on the tubesheet faces of all condensers at both plants. Using a computerized data acquisition system, potential variations were periodically measured across the tubesheet face and plotted as iso-potential diagrams.

FINDINGS

Non-destructive Examinations - The eddy current tube (ECT) probe survey of St. Lucie 1 condensers revealed that a total of 1,641 out of 47,850 tubes showed indications of tube wall hydriding greater than or equal to 50%. As illustrated in Figure 1, the 1B1 condenser inlet waterbox contained more than twice as many of these severely hydrided tubes compared to the other seven St. Lucie 1 inlet and outlet waterboxes. The survey further showed that 33,913 and 5,683 tubes fell into the 20-39% and 40-49% tube wall hydriding categories, respectively.

The Turkey Point 3 ECT tube surveys on the other hand, revealed significantly lower numbers of severely hydrided tubes, as shown in Figure 1. This involved 668 out of 44,000 tubes, 80% of which were located in the outlet waterbox of the 3B-South condenser. Furthermore, 12,415 tubes gave indications of being 20-39% hydrided, whereas 910 tubes fell into the 40-49% hydrided category. Although these ECT survey numbers actually represent the number of affected tube ends, these numbers approximate the actual number of tubes affected due to statistical reasons.

ECT probe surveys indicate that the hydriding severity was greatest at the bottom of inlet tubesheets at St. Lucie 1. On the other hand, most hydriding at Turkey Point 3 occurred in the top section of the outlet tubesheet of the one condenser. These surveys consistently showed that the degree of tube hydriding was maximum at the tubesheet joint and diminished in a continuous fashion with distance into the condenser steam space. Furthermore, 90% of the tube ends heavily obstructed with debris at St. Lucie 1 were associated with severe hydriding ($\geq$50% wall). This correlation between obstructed tubes and severe hydriding was not observed at Turkey Point.

Metallurgical Examination - The five tubes initially pulled from the St. Lucie 1B1 condenser in early 1986 exhibited microstructures with shallow (approx. 3-4 mils deep) I.D. surface hydride layers at the inlet and outlet tubesheet joint (Figure 2). Hydriding rapidly diminished within a distance of approximately 1-2 feet steamside of the tubesheet as shown in Table 1. The acicular hydride precipitates were generally oriented parallel to the tube axis in all areas examined. Tube seam welds generally remained unhydrided. The protruded outlet tube ends, however, experienced severe I.D. and O.D. surface hydriding, with penetration increasing toward the end of each tube stub. As illustrated in Figure 3, the solid hydriding which essentially consumed the ends of these protruding tubes explains why these tube ends were found cracked and flowered. The tube end cracks were relatively short in length, with cracks arresting in unhydrided tube wall metal at least 1 inch in front of the outlet tubesheet face.

A year later, ten more tubes were extracted from the same St. Lucie 1 condenser for examination based on strong ECT probe indications. Their microstructures revealed a solid hydride layer penetrating 35-55% of the tube wall in the outlet tubesheet joint area. The micrographs in Figure 4 show how the extent of tube I.D. surface hydriding diminishes with distance into the steamspace.

Hydrogen content profile as a function of tube length, presented in Table 1, indicates that the severe hydriding is within 1 foot of the tubesheet, approaching tube base hydrogen levels (~ 70 ppm) at approximately 5-6 feet. Although tube weld seams generally exhibited significantly less hydriding and hydride penetration, weld heat affected zones did experience hydride penetration equal to and, in several cases, greater than tube base metal.

Several tubes pulled from the Turkey Point 3A-North condenser were also metallurgically sectioned and examined. These tubes exhibited solid I.D. hydride layer thicknesses ranging from 5 to 15 mils at and within 6 inches steamside of the outlet tubesheet. Also similar to the St. Lucie 1 tubes examined, these tubes exhibited somewhat increased hydride layer penetration in weld heat affected zones relative to surrounding tube base and weld metal (Figure 5). Interestingly, weld seams experienced little or no hydriding. Although a few random patches of shallow radially-oriented hydrides were observed, hydride percipitates were generally longitudinally (or tangentially) oriented as in the St. Lucie tube samples.

Mechanical Property Evaluation - Flattening tests were conducted on more than fifteen hydrided tubes extracted from St. Lucie 1 and Turkey Point 3 condensers. Tube samples tested included protruded stub ends, expanded tube joint sections and unexpanded tube segments located 1.5 and 3.0 inches into the steam space. The ASTM B-338 flattening test requires that tube samples not experience cracking when flattened to a platten distance of 0.29-0.30 inch for the 0.875-1.00 inch dia. x 0.028 inch tubes. No O.D. tube surface cracking occurred in any sample after flattening (Figure 6A), whether the weld seam was in the maximum strain position or not.

Recognizing that these flattening tests put the tube I.D. surface in compression in the area of maximum strain, reverse flattening tests were also conducted to impose tensile strain on the hydrided tube I.D. surface during flattening. Although very shallow I.D. surface checking was observed, no serious or through-wall cracking was noted regardless of weld position. As shown in the longitudinal tube wall section photomicrograph in Figure 6B, cracks can develop through the brittle solid hydride layer in flattened samples, but these cracks always arrest at the solid hydride layer/ductile metal interface. This demonstrates that the remainder of the tube wall which is unhydrided retains its inherent ductility and toughness, sufficient to inhibit further growth of cracks initiated in the hydride layer.

Tensile tests were performed on two severely hydrided tubes extracted from the St. Lucie 1B1 condenser. As Table 2 results show, the severely hydrided tube sections (located 3 inch into the steam space) exhibited 10-17% lower yield strength values, 9-12% lower ultimate strength values, and a 16-35% reduction in gross ductility compared to unhydrided mid-span tube samples. Despite these reductions, the absolute values of these tensile properties are still quite substantial and appear to indicate good basic mechanical integrity of the tubes. Total elongation of the 50% hydrided tube is still 15-16%, indicating that these tubes can still accommodate significant plastic strain and resist measurable physical damage. No direct proportionality between percent through-wall hydriding and strength is apparent, suggesting that the hydride layer is, in fact, accommodating part of the load despite its brittle nature.

After the tensile test, the R81-T22 tube tensile sample fracture surface was examined under the SEM. The fractograph, shown in Figure 7 at approximately 350X, reveals the transition from low energy brittle (cleavage) fracture associated with the solid I.D. surface hydride layer to the high energy, highly ductile fracture observed throughout the remaining unhydrided tube wall up to and including the tube O.D. surface.

Internal hydrostatic pressure tests were conducted on a severely hydrided St. Lucie 1B1 (R81-T19) tube to determine tube integrity in the hoop direction. The 35% hydrided tube sample obtained from 3 inches into the steam space, did not leak or burst when pressurized up to 1800 psi. Thus, no serious detrimental effect of hydriding is noted in the hoop direction, with I.D. pressure capability well above that required by the ASME Pressure Vessel Code (810 psi at 120°F).

Tube Hoop Stress Analysis - Hoop stress analysis was performed on a representative St. Lucie 1 condenser tube to consider how residual stress states in the tube may influence tube hydriding or affect hydrided tube metal. Tube hoop stress was determined by slitting the tube sample along the weld seam and measuring any resultant changes in the tube O.D. Stress values were calculated from the following expression:

$$S = \left(\frac{E}{1-\mu^2}\right)(t)\left(\frac{1}{D_1} - \frac{1}{D_2}\right)$$

where:

S = hoop stress (psi)
E = modulus of elasticity (psi)
μ = Poisson's Ratio
t = tube wall (inches)
D_1 = initial O.D. (inches)
D_2 = final O.D. (inches)

Values for tube I.D. and O.D. surfaces were measured after pickling away 50% of the original tube wall from either the tube O.D. or I.D. surface prior to tube slitting.

The results of this analysis are outlined in Table 3. The unexpanded titanium tube within the condenser steam space reveals a slight compressive hoop stress at or near tube I.D. surfaces, transitioning into a tensile stress toward the O.D. surface. On the other hand, the transition zone between expanded and unexpanded tubing just behind the tubesheet exhibits measurable compressive stress through the tube wall section. Although the extracted expanded tube joint sample exhibited compressive stress only near the tube I.D. surface, it can be assumed that highly compressive stresses exist throughout the expanded tube wall within actual condenser tubesheet joints.

The compressive residual hoop stress identified in expanded titanium tubing within tubesheet joints and transition zones is considered to be beneficial in retarding crack initiation and propagation (despite the presence of brittle hydrides), particularly in the longitudinal tube direction. The small, but finite compressive stress at tube I.D. surfaces within the condenser is also favorable in alleviating driving forces for I.D. hydride layer cracking.

DISCUSSION

Effect of Tube Hydriding - The tensile, flattening, and hydrostatic pressure tests conducted on severely hydrided condenser tubes suggest that the mechanical and physical tube integrity are more than adequate for condenser service in terms of static loads anticipated. The unhydrided tube wall remaining in affected tubes has been shown to exhibit good tensile strength and ductility, and excellent toughness in resisting further growth of I.D. hydride layer-initiated cracks. Vendor stress analysis of the St. Lucie 1 condenser indicates that static longitudinal tensile stress levels on condenser tubes depend on tube location, and may range as high as 18 ksi tension in outer peripheral tubes to compression on inner core tubes of the condenser. Clearly the total static stress, which is greatest (in tension) on peripheral tubes, is well below the tensile strength values exhibited by severely hydrided tubes and failure is not predicted. In addition, operating condenser tube I.D. pressures of less than 100 psi and low shellside (condensing steam) pressures are of no concern when one considers the favorable hoop direction tube properties measured.

It should be recognized that the mechanical properties of the hydrided tubes discussed was based on a limited number of tube samples. Therefore, additional tubes will be tested, as they become available, to verify these findings.

The favorable longitudinal (or tangential) orientation of the hydride phase platelets precipitated in the condenser tube walls appears to reduce the extent of penetration of local brittle (hydride) pathways into the tube wall. Titanium hydride phase orientation is strongly influenced by both metal crystallographic texture and state of residual stress in the tube wall. The highly compressive tube hoop stress within the tube joint area and transition zone (Table 3) is known to promote this favorable hydride phase orientation, while inhibiting tube crack initiation. Tubing within the condenser steam space normally exhibits slight compression at or near tube I.D. surfaces, becoming more compressive as a result of I.D. surface hydride layer formation and growth. All of these test results and these obsevations appear to help explain why condenser tube failure has not occurred in either FP&L plant despite the severe degree of hydriding noted.

However, consideration must also be given to the possible detrimental influence of tube hydriding on condenser tube fatigue life, particularly in peripheral tubes where steam induced deflection and static tensile stresses are highest. Shellside steam flow can induce tube vibration and swirl which imposes longitudinal cyclic stresses in tubes. Tube hydriding reduces tube section thickness, and provides brittle surface layers where fatigue pre-cracks may quickly form; thereby, possibly reducing fatigue life given sufficient cyclic stress levels.

Preliminary data from strain gages installed on several tubes adjacent to St. Lucie 1 tubesheets indicates that rather low (50 psi) cyclic stress levels are imposed on peripheral tubes during normal condenser operation. This may, in part, be the result of the short unsupported tube span of approximately 26-28 inches between tubesheet and nearest tube support plate in St. Lucie 1 and Turkey Point 3 condensers. Although these factors may explain why no hydride related fatigue problems have been observed to date in these units, significantly higher short-term cyclic stresses are known to occur during unit start-ups and shutdowns. Comparative tube fatigue tests are being planned to address these more severe operational demands on condenser tubing.

Cause of Tube Hydriding - Good correlation between hydrided tube location and C.P. anode proximity, C.P. current level, and tubesheet isopotential profile data, combined with the diminishing distribution of tube I.D. surface hydrides from tube ends into the steamspace, support the notion that waterbox C.P. system cathodic charging was the cause of tube hydriding. The protruded tube ends originally discovered at St. Lucie 1 experienced the greatest degree of hydride penetration (and embrittlement) because of their proximity to waterbox anodes and much higher cathodic current densities associated with electric point effects. Although C.P. potential levels were normally adjusted to -0.9 volts (vs. $Cu/CuSO_4$), actual local impressed potentials on the tubesheets were more negative than -1 volt. This was due to inhomogeneity of cathodic current density across the tubesheet surface, increasing cathodic polarization of waterbox and tubesheet surfaces with time[1], and the remote locations of the reference electrodes. Current "hot spots" caused by anodes in very close proximity to tubesheets at both plants produced even more negative local potentials. Furthermore, plant records reveal that C.P. currents approximately double those normally set were inadvertently impressed on the Turkey Point 3B-South outlet waterbox for period of two weeks. This may have resulted in tubesheet potentials in the range of -1.5 to -2.0 volt range. As expected, this particular condenser experienced the highest degree of tube hydriding at this plant.

The literature indicates that impressed cathodic potentials more negative than -0.75 volts SCE can result in surface hydrogen charging and related hydrogen absorption by unalloyed titanium in ambient seawater.[2-5] These studies have shown that cathodic potentials up to -1.0 volt SCE produce only minimal hydrogen uptake in titanium, in the form of thin (<1-2 mils thick), innocuous surface hydride layers at temperatures below 170°F. The fact that these condenser tubes experienced hydride penetration well into the tube wall suggests that actual impressed potentials were indeed in excess of -1 volt SCE, assuming that tube wall temperatures remained below 170°F in service. Better resolution of hydrogen absorption/hydride penetration rate versus impressed cathodic potential at potentials more negative than -1 volt SCE was not possible due to the lack of published information. Laboratory cathodic charging studies are currently underway on grade 2 titanium tube samples to assess the influence of cathodic potentials on tube hydriding in the -1 to -2 volt range.

CORRECTIVE MEASURES

Recognizing that continued hydrogen absorption and hydriding of titanium condenser tubes could result in eventual brittle failure of affected tubes, remedial measures were promptly implemented at both FP&L plants. Most of these measures aimed at eliminating excessive cathodic charging of nascant hydrogen on condenser tube surfaces, considered to be the root cause of tube hydriding. These specific measures included:

1. Installing potential-controlled impressed cathodic protection systems in each condenser waterbox, replacing the manually controlled rectifier systems originally installed. A constant cathodic potential (potentiostatic control) is provided for tubesheet/waterbox protection by continuous potential feedback from a waterbox wall-mounted Ag/AgCl reference electrode.

2. Adjusting impressed cathodic potentials to a constant level of -0.7 volts (vs. Ag/AgCl) to assure that no further reduction (charging) of hydrogen occurs at condenser tube surfaces, thus preventing further hydriding of tubes.

3. Coating all seawater-side inlet and outlet tubesheet surfaces with epoxy to significantly reduce impressed cathodic current requirements for protecting tubesheets. This provides more uniform cathodic current distribution and allows for effective cathodic protection at reduced impressed cathodic potential levels.

4. Installation of face-mounted Ag/AgCl reference electrodes on tubesheets to provide periodic monitoring of tubesheet face impressed potential levels. Data from six reference electrodes strategically positioned on each tubesheet provide an approximate potential profile across each condenser tubesheet face.

5. Based on Measure #4 and tube ECT survey data, modify anode type, geometry, and/or position to achieve more uniform impressed cathodic potentials on tubesheet faces and limit local charging hot spots. Specifically, the silicon iron button anodes in St. Lucie 1 waterboxes were replaced with platinized-titanium rod anodes spaced equi-distant from each other on the rear waterbox wall at a minimum distance of 18 inches from each tubesheet. At Turkey Point 3, the waterbox or side wall-mounted graphite anodes closest to each tubesheet were disconnected to eliminate the local hot spots created by their close proximity.

6. Plug all condenser tubes which gave ECT probe indications of ≥ 50% through-wall hydriding using conventional rubber plugs. Although none of these heavily hydrided tubes experienced leakage or failure to date, this conservative measure was instituted as an added safeguard against condenser-related unit outages in the future.

CONCLUSIONS

1. Significant hydriding of titanium surface condenser tube has been identified and characterized at FP&L's St. Lucie 1 and Turkey Point 3 condensers.

2. Tensile, flattening, and hydrostatic pressure testing of severely hydrided tubes indicates good mechanical and physical integrity in affected tubes. These appear to be adequate for continued condenser service based on static tube stress levels anticipated during operation. The influence of tube hydriding on practical tube fatigue life has yet to be assessed.

3. Tube I.D. surface hydriding appears to be the direct result of excessive cathodic potentials/currents (> 1 volt SCE) impressed on tube surfaces by waterbox/tubesheet cathodic protection systems.

4. Several remedial measures have been implemented at both FP&L plants to avoid further tube hydriding by limiting the cathodic charging of hydrogen on condenser tube I.D. surfaces.

REFERENCES

1. J. Morgan, Cathodic Protection, 2nd Edition, National Association of Corrosion Engineers, Houston, TX, 1987, page 52.

2. H. Satoh, T. Fukuzuka, K. Shimogori, and H. Tanabe, "Hydrogen Pickup by Titanium Held Cathodic in Seawater," Paper presented at 2nd International Congress on Hydrogen in Metals, June 6-11, 1977, Paris, France.

3. S. Sato, K. Nagata, M. Nagayama, "Experience[illegible] of We[illegible] Titanium Condenser Tubes in Japan," Sumitomo Light Metal Ind. Ltd., Technical Research Laboratory, Nagoya, Japan.

4. T. Fukuzuka, K. Shimogori, H.Satoh, and F. Kamikubo, "Corrosion Problems and Countermeasures in MSF Desalination Plant Using Titanium Tube," Kobe Steel Ltd. Reprint, Kobe, Japan, 1985.

5. "Get More Advantages By Applying Titanium Tubing Not Only For Power Plants But Also For Desalination Plants!!," Technical Brochure prepared by the Japan Titanium Society, [illegible].

[IP12_003157]

ACKNOWLDEGEMENTS

The authors wish to acknowldge the technical contributions of the following individuals to this investigation: James Grauman of TIMET Corp.; and Steve Collard, Wolfgang Heise, Mark Joseph, and Randy Newnam of Florida Power and Light Co. Cooperation from the staff of the St. Lucie and Turkey Point power plants is also appreciated.

Table 1 Hydrogen Content Profiles Of St. Lucie 1B1 Tubes

Sample Location	Tube Sample Hydrogen Content (ppm) R78-T6 Tube	R66-T17 Tube	R81-T23 Tube	R82-T13 Tube
Outlet Protruded End	3900	1406	4900	7400
Center Of Outlet Tubesheet	--	--	3600	6800
1 in. steamside	2340	1250	--	--
4 in. "				
8 in. "	907	1015	--	--
12 in. "	1150	1001	--	--
24 in.	490	570	227	732
36 in. "	164	181	130	130
48 in. "	--	--	103	123
72 in. "	--	--	90	73
120 in. "	--	--	88	71
Mid-length	--	--	67	68

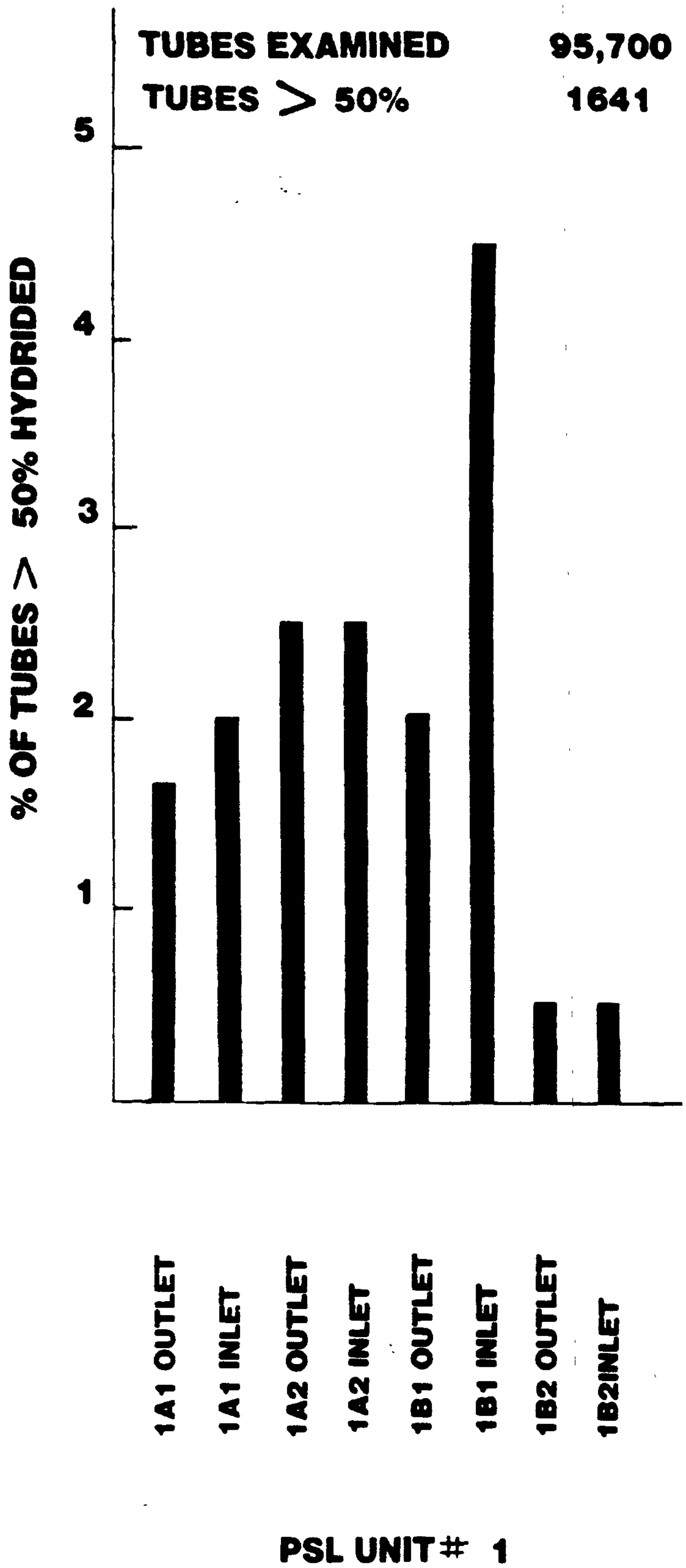
Table 2 Tensile Test Results For St. Lucie 1B1 Tubes

Tube No.	Sample Location	Condition	YS (ksi)	UTS (ksi)	Local Elong. (%)	Total Elong. (%)
R81-T13	Mid-length	No hydriding	49.2	71.1	50	20
R81-T13	"	"	49.6	70.2	65	18
R81-T13	3" from outlet tubesheet	33% hydrided	44.6	62.2	28	16
R81-T22	Mid-length	No hydriding	49.2	69.0	45	23
R81-T22	3" from outlet tubesheet	49% hydrided	40.8	63.1	20	15
R81-T22	8" from outlet tubesheet	12% hydrided	47.7	69.3	25	15

Table 3 Residual Hoop Stress Analysis Of St. Lucie 1 Tubing

Tube Sample Location	Hoop Stress* Toward I.D. Surface	Toward O.D. Surface	Total Section
Unexpanded, within steam space	-0.5 (ksi)	+11 (ksi)	+14 (ksi)
Transition zone	-3	-32	-25
Expanded, within tubesheet joint	-8	+3	+33

* + values indicate tension
- values indicate compression


TUBES EXAMINED 95,700
TUBES > 50% 1641
% OF TUBES > 50% HYDRIDED
1
2
3
4
5
1A1 OUTLET
1A1 INLET
1A2 OUTLET
1A2 INLET
1B1 OUTLET
1B1 INLET
1B2 OUTLET
1B2INLET
PSL UNIT # 1

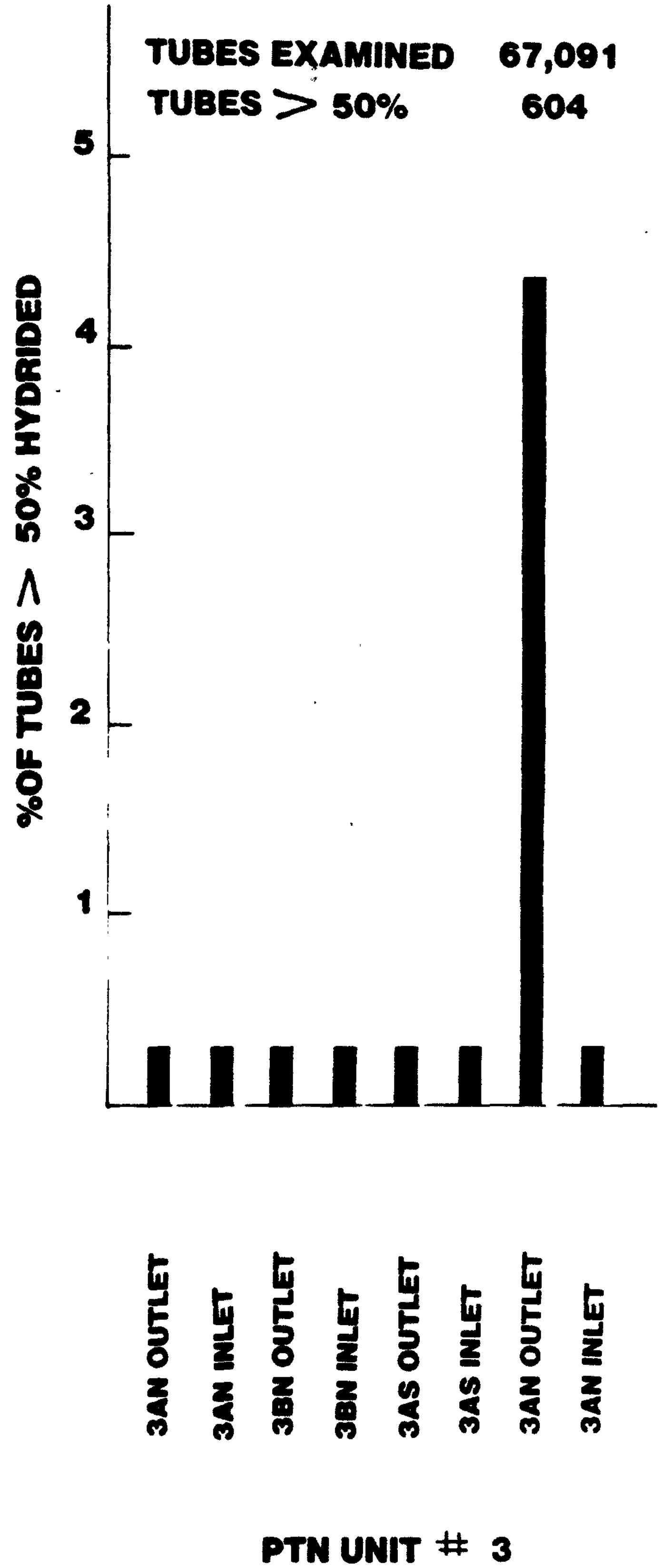
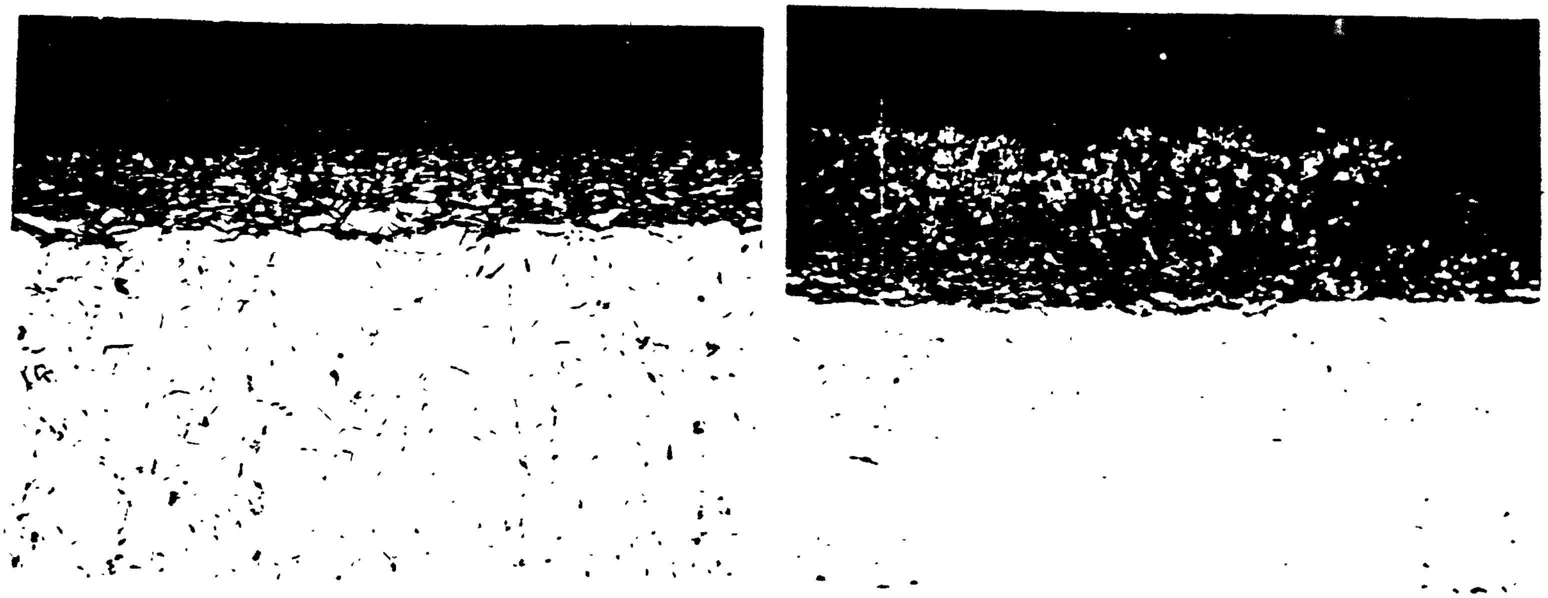

TUBES EXAMINED 67,091
TUBES > 50% 604
%OF TUBES > 50% HYDRIDED
1
2
3
4
5
3AN OUTLET
3AN INLET
3BN OUTLET
3BN INLET
3AS OUTLET
3AS INLET
3AN OUTLET
3AN INLET
PTN UNIT # 3

Figure 1



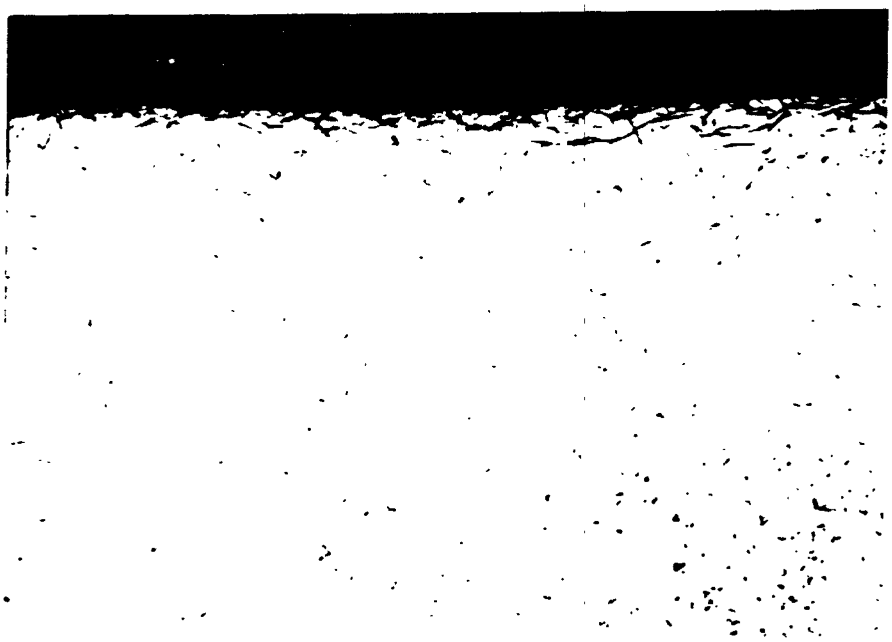
A. Located 1 inch steamside of outlet tubesheet. (200X)

B. Located within inlet tubesheet joint. (200X)

Figure 2: Transverse section photomicrograph of the R78-T6 St. Lucie 1B1 tube showing I.D. surface hydride layers.

Figure 3: Longitudinal section photomicrographs of the R78-T6 St. Lucie 1B1 tube, in area up to and including the protruded outlet tube end (stub end). Note the increasing severity of I.D. and O.D. surface hydriding toward the tube end.

A. Located within outlet tubesheet joint at 100X.



B. Located 2 feet steamside of the outlet tubesheet at 200X.

Figure 4: Section photomicrographs of the R82-T13 St. Lucie 1B1 tube, showing I. D. surface hydride layers at two locations.

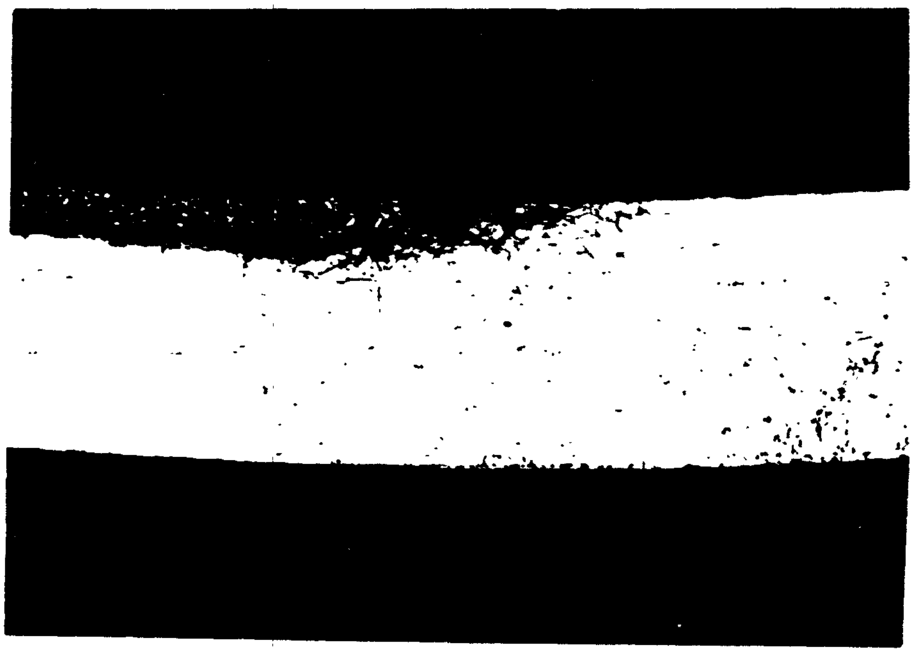
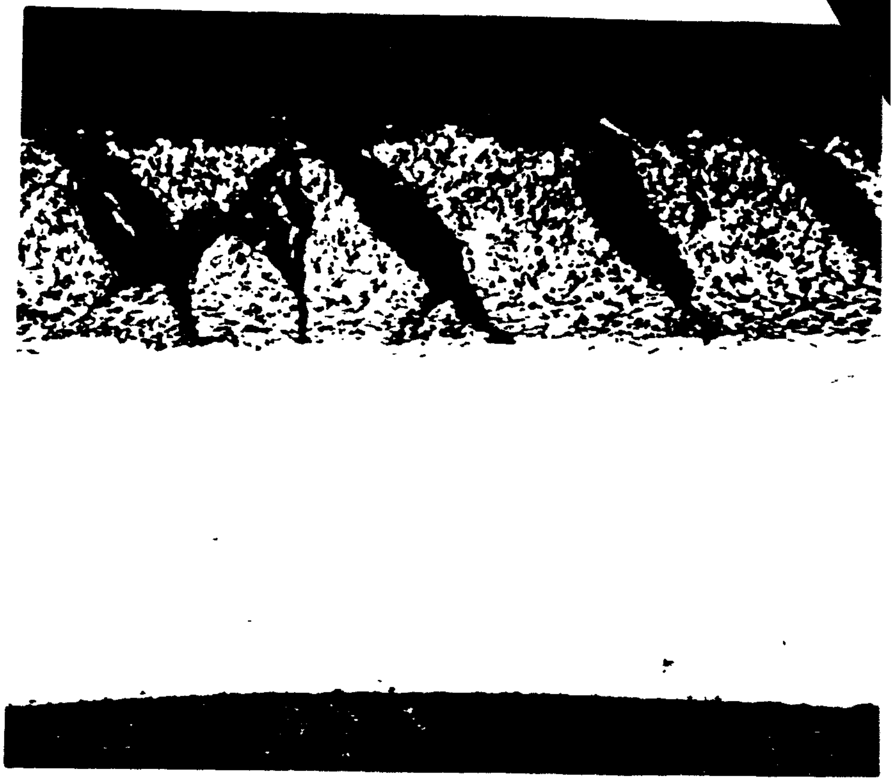


Figure 5: Transverse section photomicrograph of the R308-T1 Turkey Pt. 3A-North tube at an area several inches steamside of the outlet tubesheet. Note the I.D. surface hydride layer in tube base and HAZ metal (left to center) and its absence in the weld metal (to the right).

A. Typical flattened hydrided tube sample, showing no O.D. surface cracking.



B. Transverse section photomicrograph of flattened R82-T13 tube sample (100X).

Figure 6: Flattening test results for severely hydrided tube samples. Note crack arrest at the hydride layer - tube metal interface.

Figure 7: Fractograph of pulled R81-T22 St. Lucie 1B1 tube tensile specimen at 3 inches steamside of outlet tubesheet. Note the transition from brittle fracture through I.D. surface hydride layer (bottom) to normal ductile fracture in unhydrided tube metal. (350X)